OIL SHALE TRACTS
U-A AND U-B

SUPPLEMENTAL MATERIAL

TO

DETAILED DEVELOPMENT PLAN

SUBMITTED BY

WHITE RIVER SHALE OIL CORPORATION

Oil Shale Tracts U-a and U-b

Supplemental Material to the

WHITE RIVER SHALE PROJECT

DETAILED DEVELOPMENT PLAN

Submitted by

White River Shale Oil Corporation

Compiled by
Oil Shale Office

January, 1982

Errata Sheet
for
WRSP Detailed Development Plan (DDP)
Gibbs & Hill Community and Infrastructure Support Study

WRSP DDP:

Page	
2-27	Figure 2.2-8 Soils Map of the Oil Shale Tracts - the legend does not accurately identify the (R) symbol on the soil map. It is described as "shallow channery and flaggy loams" where as table 5.5-1 describes R as massive sandstone. This is a minor point but could be misleading.
2-34	Omitted 695 from parenthesis - bottom of page.
2-140	Top line. Kentucky bluegrass (*Poa pratensis*) should be Sandburg bluegrass (*Poa secunda*). *Poa pratensis* isn't found under a juniper canopy or in this juniper vegetation type.
2-172	Last paragraph: Arid climate stated here; yet, on pages 1-14 it is stated as semiarid climate.
2-190	"inflow" should be "streamflow"
2-207	Last paragraph: The Uinta Formation should read - The Green River Formation.
3-1	2nd line. "Above ground" should be two words.
3-153	There are inconsistencies between the flow chart and the tract, e.g., late-use of high TDS water.

Gibbs & Hill Study

Page	
3-5	Fifth paragraph -- 42 cfs would be a rate of flow and not a capacity. Apparently, this is a typo.
3-18	First paragraph -- This lacks a reference to the State Museum and Dinosaur Gardens in Vernal.
5-2	Second paragraph -- Believe the research was started prior to 1981. Suggest a typo in the figures.
5-6	The Reservation was established in 1881, not 1991 (Volume 1 of DDP, p. 1-17).
7-10	First paragraph -- Should read city, county, and "State" governments.

WRSP DDP

SUPPLEMENTAL MATERIAL

PER

OCTOBER 2,1981 REQUEST

October 2, 1981

Mr. James W. Godlove
Environmental Affairs Coordinator
White River Shale Project
1315 West Highway 40
Vernal, Utah 84078

Dear Mr. Godlove:

The Oil Shale Office has completed a quick internal staff review of the Detailed Development Plan submitted to this office on September 1, 1981. Prior to the public hearings some supplemental material is required. We will send copies of some of the material to EPA, Utah State, BLM, and OSEAP, while the remainder will be for internal review only. Additional materials may be requested following the results of our indepth review, public hearings, OSEAP meeting in Salt Lake City, and public comments.

The supplemental material currently required is as follows:

1. An updated permit schedule. The schedule in Section 3 was not updated from the previous draft.

2. A more detailed capital and operating cost estimate to supplement the summary of estimated costs given on page 1-26. This supplemental cost information would be considered confidential and handled accordingly.

3. A detailed write up on the secondary impacts such as sludge, water, and electricity based on commercial phase modeling of Flue Gas Desulphurization units.

4. A revision to Figure 3.5-7 that shows the ventilation direction in the panels reversed in order to comply with gassy mine regulations. Figure 3.5-5 should be revised to show a pillar in the mined panels below the decline in the westerly direction.

5. A process monitoring plan is needed. This plan should include details on determining process emissions and for collecting data on process streams such as oil shale feed, shale oil, process gas, water, and processed shale. The monitoring should be designed to collect comprehensive data for energy and material balances and to evaluate source material and products for process efficiency evaluations and for environmental concerns.

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6. More details on the water management plan. The plan is vague concerning segregation of different sources of water on tract during the different phases. Of special concern is the potential contamination of relatively clean water with process "sour" water. The plan should include the handling of excess mine water in the event it is encountered.

7. Noise impact Section 5.2.8 was not included in the DDP but was in the previous drafts. Explain the omission.

8. Clarification of pollution control measures as to whether vapor recovery systems or flaring will be used. Sections 3.8.6 indicates a decision to be made but Section 4.2.2 states a number of flare stacks have been provided. If the decision has been made, OSO needs the rationale and justification for the selection.

9. An emission points plot plan for Phase II. Both Phases I and III are given. You have stated earlier that Phase II will be one half of Phase III, however; a plot plan is needed for Phase II since its configuration will be much different than either Phase 1 or Phase III.

10. More detailed information on the oil and gas wells that have been drilled on Tracts U-a and U-b. There is a discrepancy in the DDP as to the number drilled. The information should include: exact number and location of wells; completion status; status of one producing well; ownership; status of any oil/gas leases on tracts.

This information should be provided as early as possible to allow distribution and staff review prior to the public hearings.

Sincerely,

Peter A. Rutledge
Deputy Conservation Manager
Oil Shale

RAT:wr

WHITE RIVER SHALE PROJECT
1315 WEST HIGHWAY 40
VERNAL, UTAH 84078
(801) 789-0571

October 20, 1981

RECEIVED

OCT 22 1981
OFFICE OF
AREA OIL SHALE SUPERVISOR
U.S. G.S.

Mr. Peter A. Rutledge
Deputy Conservation Manager-Oil Shale
Oil Shale Office
131 North 6th Street, Suite 300
Grand Junction, Colorado 81501

Dear Mr. Rutledge:

Your letter of October 2, 1981 requested additional information to assist your review of the Detailed Development Plan submitted for the White River Shale Project. Attached to this letter is the supplemental material requested.

Please advise if you have further questions.

Sincerely,

James W. Godlove
Environmental Affairs Coordinator

JWG:ddb

Attachments (6)

810919

WHITE RIVER SHALE OIL CORPORATION
RESPONSE TO REQUEST FOR
SUPPLEMENTAL MATERIAL TO DDP BY
USDI OIL SHALE OFFICE

OSO REQUEST NO. 1: An updated permit schedule.

WRSOC RESPONSE NO. 1: Attachment No. 1 is the current permit schedule for the project. This schedule addresses only those generic permits needed for on-tract development. As the project schedule becomes more well-defined and as our off-tract development needs are identified, revisions to this permits schedule will be made. The OSO will receive updated schedules as they are prepared.

OSO REQUEST NO. 2: A more detailed capital and operating cost estimate to be handled as confidential material.

WRSOC RESPONSE NO. 2: WRSOC is preparing a more detailed estimate of project costs for the OSO. This confidential material will be provided to the OSO by November 2, 1981.

OSO REQUEST NO. 3: A detailed write-up on the secondary impacts of Flue Gas Desulfurization (FGD) technology installed during commercial phases.

WRSOC RESPONSE NO. 3: The boiler plants for the project will use treated low Btu by-product offgases (from Superior retorts) and supplemental upgraded shale oil as fuel to provide steam and electric power (Phases II and III only) to the oil shale processing plant. The flue gas from these boilers will have a very low concentration of sulfur dioxide, being on the order of 85 ppm. This was judged by the project to represent best available pollution control technology.

However, to comply with the currently applicable Prevention of Significant Deterioration (PSD) Class II increments for SO_2 during the commercial phases of the project, the boilers were equipped with flue gas desulfurization units designed to remove an additional 80 percent of the SO_2 in the boiler flue gases. (It is planned that the Phase I steam plant will be retrofitted with FGD during Phase II. The Phase II and III steam plants will be constructed including FGD systems, as appropriate.)

For purpose of the DDP, it has been premised that the FGD system will be a non-regenerable limestone system. However, as an alternate (Section 7 of the DDP), it may be practical to consider a regenerable, ammonia based scrubbing system.

The anticipated FGD system characteristics are presented in Attachment No. 2 for both the primary (limestone) and alternate

(ammonia) systems. In deriving these figures, several assumptions were made as follows:

a. Inlet gas humidity is 0.150 lb. H_2O/lb. dry gas and exits the scrubber at 144°F saturated.

b. Liquid to gas ratios (gpm/1000 acfm) are:
60 L/G for limestone system
10 L/G for ammonia system

c. Overall FGD sulfur removal efficiency would be 80% due to the low inlet SO_2 concentration.

d. Total system pressure drops are:
10 in. H_2O for limestone system
20 in. H_2O for ammonia system

e. The treated flue gas would be reheated by indirect steam heat exchange.

f. The final waste (or by-product) materials would be non-hazardous, consisting of 80% solids (a mixture of calcium sulfite and calcium sulfate) for limestone system or 40% ammonium sulfate solution for the ammonia scrubber.

To summarize the secondary impacts of FGD systems for limestone scrubbing:

	Phase I	Phase II	Phase III[a]
Electrical power (KW)	0	2400	6900
Water consumption (GPM)	0	167	502
Sludge production (T/day)	0	9.8	29.5
Limestone import (T/day	0	4.9	14.5

[a] includes the impacts of the Phase II units.

These values would be additive to the impacts shown in Section 3 of the DDP, which inadvertently excluded the secondary impacts of FGD systems. Thus, with limestone scrubbing during Phases II and III, the power requirements would increase 2% (to 133 MW) and 3% (to 250 MW), respectively; the water consumption would increase 3% (to 6,497 GPM) and 4% (to 14,514 GPM), respectively; and the sludge production would increase 7% (to 146 TPD) and 11% (to 302 TPD), respectively. The sludge produced would be considered non-hazardous and would be conveyed to the processed shale disposal area with the processed shale.

For ammonia scrubbing, the additive secondary impacts due to FGD would be:

	Phase I	Phase II	Phase III
Electrical power (KW)	0	2400	7000
Water consumption (GPM)	0	170	512
By Products (T/day)	0	18.5	54.7

If ammonia scrubbing were used, by-product ammonium sulfate would be sold as a fertilizer (assuming a market existed).

OSO REQUEST NO. 4: A revision to Figure 3.5-7 showing the ventilation direction reversed. A revision to Figure 3.5-5 to show pillar in mined panels below westerly decline.

WRSOC RESPONSE NO. 4: WRSOC is continuing to review Figure 3.5-7 concerning ventilation direction in the mined panels. We will advise the OSO of our findings and decision in this matter shortly. Of course, the final design will fully comply with applicable mine safety regulations. Attachment No. 3 is Figure 3.5-5 revised, as requested.

OSO REQUEST NO. 5: A process monitoring plan is needed. This plan should include details on determining process emissions and for collecting data on process streams such as oil shale feed, shale oil, process gas, water, and processed shale. The monitoring should be designed to collect comprehensive data for energy and material balances and to evaluate source material and products for process efficiency evaluations and for environmental concerns.

WRSOC REQUEST NO.5: On page 3-98 of the DDP, the following list of process monitoring parameters was identified:

a. Flow rate of raw shale

b. Flue and product gas composition, quantity, and temperature

c. Retorting temperature

d. Air and supplemental fuel flow rates

e. Volume, weight, temperature, and composition of water, oil, gas, and processed shale from the retorts

f. Sulfur and ammonia by-product production

g. Quantity of processed shale cooling water

h. Wastewater treatment

i. Other data for material and energy balances, and for emission and waste monitoring

WRSOC believes this represents a commitment by the project to collect comprehensive process data to satisfy both our internal operational needs and the OSO's lease compliance related needs. However, the details of the process monitoring program cannot be presented until additional design engineering is completed. During process development and piping and instrumentation diagram development, details on sampling and analyzing systems will be determined in detail. Thus, WRSOC will provide, prior to surface facility construction, a detailed process monitoring plan for review and approval by the OSO.

OSO REQUEST NO. 6: More details on the water management plan. The plan is vague concerning segregation of different sources of water on tract during the different phases. Of special concern is the potential contamination of relatively clean water with process "sour" water. The plan should include the handling of excess mine water in the event it is encountered.

WRSOC RESPONSE NO. 6: Details of the WRSOC wastewater management plan are given in Section 3.15 of the DDP. Figures 3.15-1 through 3.15-3 show in detail our plans to collect, treat, and reuse project wastewaters during each phase of the project. At this time, WRSOC believes the scheme described in these figures is an appropriate means of handling our wastewaters. As additional design information becomes available on the various sources of wastewater or their source characteristics, changes warranted by the new information can be made. Our design philosophy will be to maximize reuse of collected wastewaters and to co-mingle waters prior to reuse only where their characteristics are compatible with the designated reuse plan.

Concerning process sour water, there will be two sources within the plant. The first is the effluent waters formed during retorting. The second is sour water resulting from the hydrotreating of raw shale oil.

Retort water contains ammonia, hydrogen sulfide, several dissolved hydrocarbons (including phenol) and dissolved salts. Is is planned to steam strip the water to remove ammonia and hydrogen sulfide, then to dispose of the stripped water as a spent shale moistening agent, if suitable. This method will need to be confirmed following additional process design work and retort water characterization. Retort sour water (because of its poor quality) will probably not be co-mingled with other higher quality treated plant wastewaters.

Hydrotreater sour water will also be steam stripped and is of sufficiently high quality to permit its reuse in the water-wash sections of the hydrotreater.

Mine water inflows are expected to be low or nil. Such water, if encountered, will be saline and will be used for dust suppression within the mine. Any excess water would be pumped to the surface wastewater holding pond for evaporation or reuse.

OSO REQUEST NO 7: Noise impact Section 5.2.8 was not included in the DDP. Explain the omission.

WRSOC RESPONSE NO. 7: During publication of the final DDP, Section 5.2.8 was inadvertently omitted. The section is provided as Attachment No. 4 to this document.

OSO REQUEST NO. 8: Clarification of pollution control measures as to whether vapor recovery systems or flaring will be used. Sections 3.8.6 indicate a decision to be made but Section 4.2.2 states a number of flare stacks has been provided. If the decision has been made, OSO needs the rationale and justification for the selection.

WRSOC RESPONSE NO. 8: Section 3.8.6 of the DDP states that aspects of the WRSOC pollution control program will include:

- Connection of various process blowdowns, reliefs, and vents to either vapor recovery systems or emergency flares as appropriate to the size and frequency of the problem.

- Use of vapor recovery systems and/or flaring for purge gas flows during process unit turnarounds or maintenance forced shutdowns.

During the design of process units, it is our intent to recover by-product vapors wherever practical, according to established industry practice. However, in those instances of start-up, shutdown, maintenance, or unusual or emergency upset conditions (as discussed in Section 4.2.2), it will be necessary to dispose of at least a portion of the "vapors" in flares.

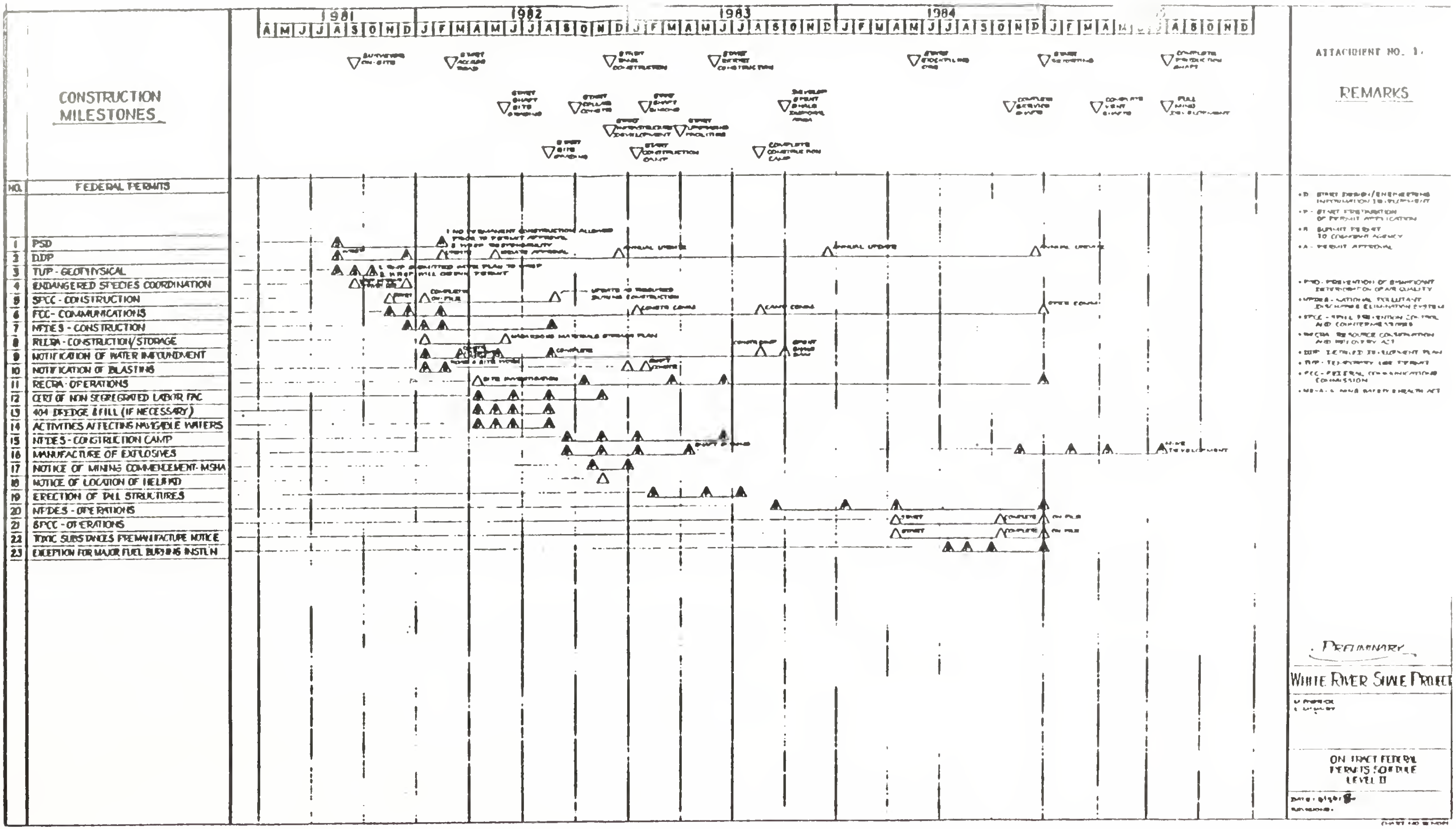
Attachment No. 5 provides a general design basis for the plant's flare headers. WRSOC will provide more detailed design rationale for the flare systems once they are designed. This information will also be provided to the Utah Bureau of Air Quality and the USEPA for review.

OSO REQUEST NO. 9: An emission point plot plan for Phase II. Both Phases I and III are given. You have stated earlier that Phase II will be one half of Phase III; however, a plot plan is needed for Phase II since its configuration will be much different than either Phase I or Phase III.

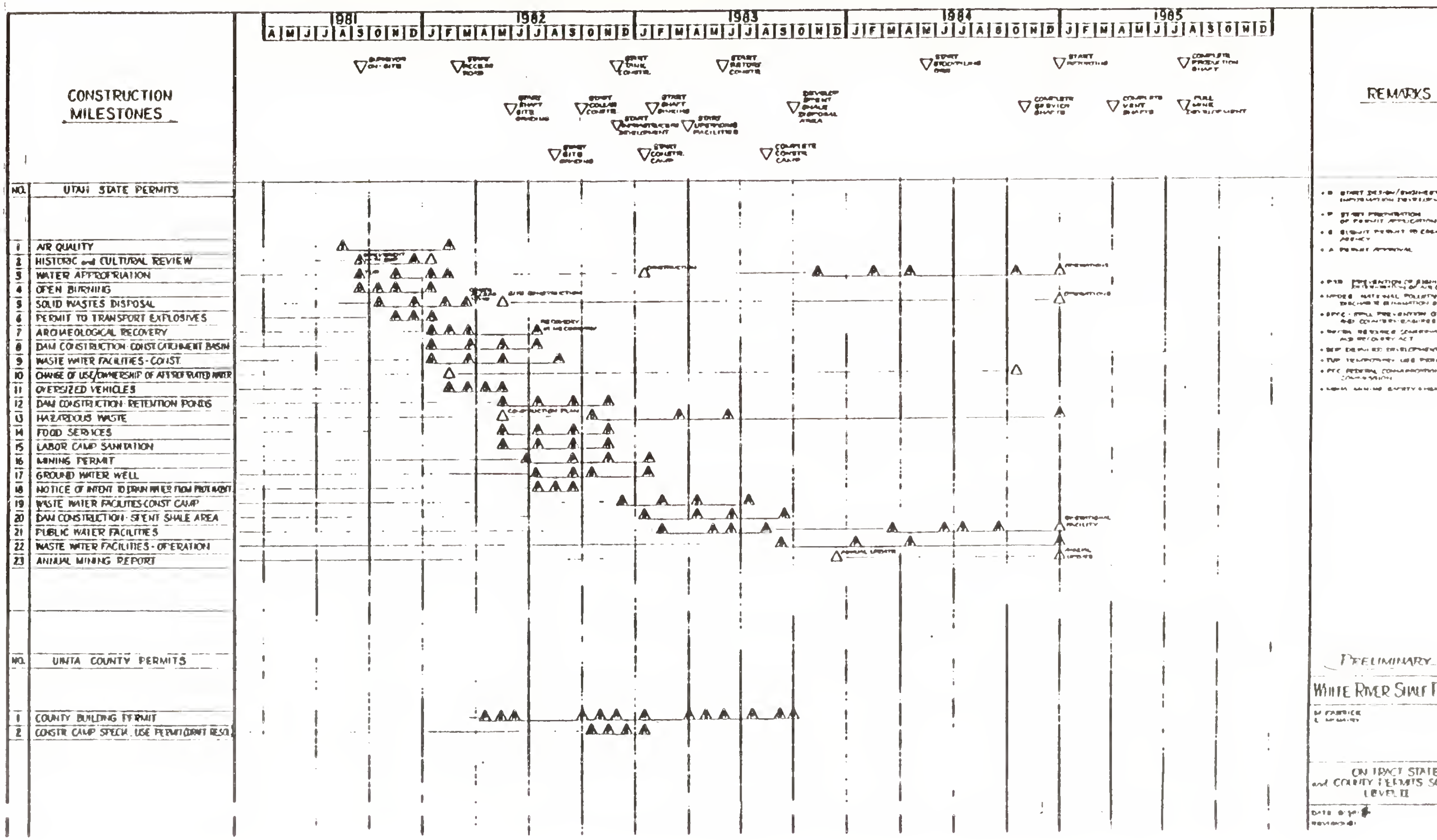
WRSOC RESPONSE NO. 9: The DDP provides a detailed emissions inventory for each phase of the project (Table Nos. 4.2-4 through 4.2-6). Since all the Phase II emission points are well identified in the Phase III emission points plot plan and in the emission inventory tables, it was believed to be redundant to include a Phase II emission points plot plan. However, for ease of identification, the Phase II facilities have been highlighted on Figure 4.2-2 and included as Attachment No. 6. Also, Tables 7-4 through 7-6 in the PSD application provide the source input data for each emission point in each phase. This is the input data used for emission modeling.

OSO REQUEST NO. 10: More detailed information on the oil and gas wells that have been drilled on Tracts Ua and Ub. There is a discrepancy in the DDP as to the number drilled. The information should include: exact number and location of wells; completion status; status of one producing well; ownership; status of any oil/gas leases on tracts.

WRSOC RESPONSE NO. 10: WRSOC is reviewing available information concerning oil and gas wells drilled on Ua and Ub. This review has not yet been completed. Our findings will be reported to the OSO shortly.



CONSTRUCTION MILESTONES
NO.
FEDERAL PERMITS
1 PSD
2 DDP
3 TUP - GEOPHYSICAL
4 ENDANGERED SPECIES COORDINATION
5 SPCC - CONSTRUCTION
6 FCC - COMMUNICATIONS
7 NPDES - CONSTRUCTION
8 RCRA - CONSTRUCTION/STORAGE
9 NOTIFICATION OF WATER IMPOUNDMENT
10 NOTIFICATION OF BLASTING
11 RCRA - OPERATIONS
12 CERT OF NON SEGREGATED LABOR FAC
13 404 DREDGE & FILL (IF NECESSARY)
14 ACTIVITIES AFFECTING NAVIGABLE WATERS
15 NPDES - CONSTRUCTION CAMP
16 MANUFACTURE OF EXPLOSIVES
17 NOTICE OF MINING COMMENCEMENT - MSHA
18 NOTICE OF LOCATION OF HELIPAD
19 ERECTION OF TALL STRUCTURES
20 NPDES - OPERATIONS
21 SPCC - OPERATIONS
22 TOXIC SUBSTANCES PREMANUFACTURE NOTICE
23 EXCEPTION FOR MAJOR FUEL BURNING INST'L'N
1981
1982
1983
1984
ATTACHMENT NO. 1
REMARKS
PRELIMINARY
WHITE RIVER SHALE PROJECT
ON TRACT FEDERAL PERMITS SCHEDULE LEVEL II


CONSTRUCTION MILESTONES
1981
1982
1983
1984
1985
A M J J A S O N D J F M A M J J A S O N D J F M A M J J A S O N D J F M A M J J A S O N D J F M A M J J A S O N D
REMARKS
NO. UTAH STATE PERMITS
1 AIR QUALITY
2 HISTORIC and CULTURAL REVIEW
3 WATER APPROPRIATION
4 OPEN BURNING
5 SOLID WASTES DISPOSAL
6 PERMIT TO TRANSPORT EXPLOSIVES
7 ARCHAEOLOGICAL RECOVERY
8 DAM CONSTRUCTION - CONST. CATCHMENT BASIN
9 WASTE WATER FACILITIES - CONST.
10 CHANGE OF USE/OWNERSHIP OF APPROPRIATED WATER
11 OVERSIZED VEHICLES
12 DAM CONSTRUCTION - RETENTION PONDS
13 HAZARDOUS WASTE
14 FOOD SERVICES
15 LABOR CAMP SANITATION
16 MINING PERMIT
17 GROUND WATER WELL
18 NOTICE OF INTENT TO DRAIN WATER FROM PROT. ...
19 WASTE WATER FACILITIES CONST. CAMP
20 DAM CONSTRUCTION - SPENT SHALE AREA
21 PUBLIC WATER FACILITIES
22 WASTE WATER FACILITIES - OPERATION
23 ANNUAL MINING REPORT
NO. UINTA COUNTY PERMITS
1 COUNTY BUILDING PERMIT
2 CONSTR. CAMP SPECIAL USE PERMIT (...)
PRELIMINARY
WHITE RIVER SHALE PRO...
ON TRACT STATE and COUNTY PERMITS SCH...
LEVEL II

ATTACHMENT NO. 2

FGD SYSTEMS	LIMESTONE		AMMONIA	
PHASE	II only (a)	III only (b)	II only (a)	III only (b)
<u>Inlet Flue Gas</u>				
SCFM @ 60°F, 1 atm	332,300	652,000	332,300	652,000
Temp; °F	350	350	350	350
Press; psia	12.2	12.2	12.2	12.2
SO_2 conc; ppm	85	85	85	85
SO_2; lbs/hr	281	551	281	551
Humidity; lbs H_2O/lb dry gas	0.15	0.15	0.15	0.15
Wet Bulb Temp; °F	144	144	144	144
Reagent; lbs/hr	410	800	135	265
Reagent purity; %	95	95	90	90
Process Water; GPM	167	335	170	342
Air for Oxidation; scfm	105	212	105	212
<u>Electric Power</u>				
ID Fan; HP	2 @ 600 ea	4 @ 600 ea	2 @ 1200 ea	4 @ 1200 ea
Pumps; HP	1470	2960	400	810
Auxilliary; HP	120	200	40	70
Total Electricity; KW	2400	4500	2400	4600
<u>Flue Gas Reheat</u>				
Gas temp in; °F	144	144	144	144
Gas temp out; °F	350	350	350	350
Sat. Steam; lbs/hr	88,000	172,000	73,000	157,000
Steam Temp; °F	256	256	256	256
Steam Press; psia	33	33	33	33
<u>Gas to Stack</u>				
SCFM @60°F; 1 atm	361,000	708,300	361,000	708,300
Temp; °F	350	350	350	350
SO_2 conc; ppm	16	16	16	16
SO_2; lbs/hr	56	110	56	110
<u>Waste Stream</u>				
Flow Rate; lbs/hr	815.2	1644	1540	3020
Composition; wt %	80 calcium sulfite calcium sulfate 20 water		40 ammonium sulfate solution 60 water	

a) The Phase II values assume retrofit of the Phase I boilers and equipping Phase II boilers with FGD as built. Thus, both Phase I and Phase II boilers values are shown.

b) The Phase III values are for Phase III boilers only.

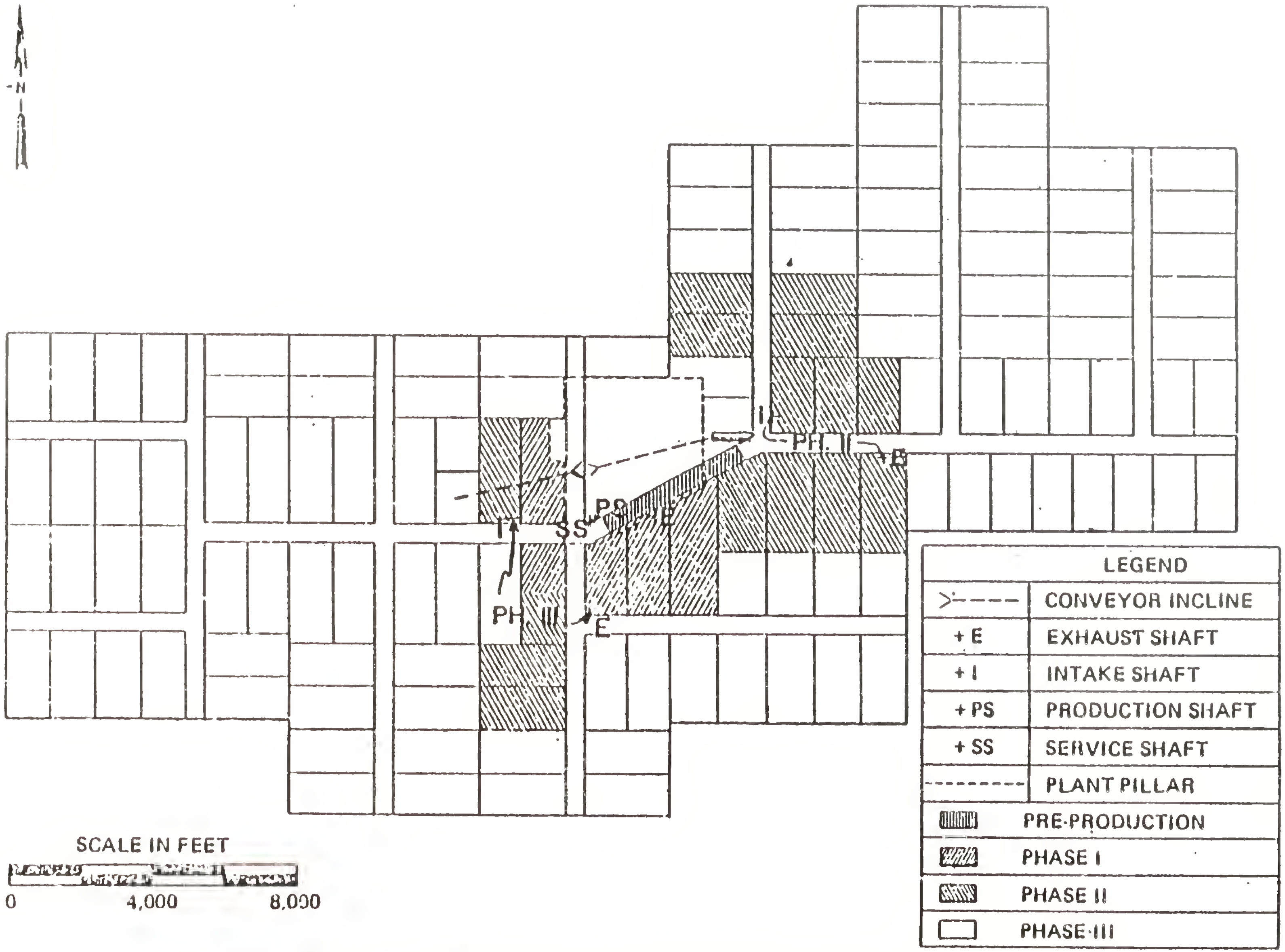


Figure 3.5-5 PANEL EXTRACTION SCHEDULE

Revised 10/19/81

ATTACHMENT NO. 4

5.2.8 NOISE IMPACTS

The following paragraphs discuss noise impacts of the project in each phase, both on tract during construction and operation and off tract.

5.2.8.1 Phase I

Construction Noise. Noise caused by construction activities will depend on day-to-day schedules, variation in equipment operation, weather conditions, and other factors. Since these variables may change from time to time during the construction period, noise level estimates and impact evaluations for construction activities are based on expected maximum or worst conditions. The noisiest activities during construction will be blasting, excavation, and clearing and grading of the site.

Since there are no residents within the tract area, the on-tract impact of construction noise will be limited to construction workers. An estimated 50 workers will be directly involved with the operation of earth-moving equipment, rock drills, and blasting activities. These personnel may be exposed to higher noise levels than others on the project.

The noise level inside the cabs of earth-moving equipment may be as high as 105 dBA, depending on the type, capacity, mode of operation, acoustical treatment, and other factors. The noise level of rock drills near the ears of the operators may exceed 100 dBA.

The nearest community is Bonanza, approximately 5 miles from the tract, and separated from the facility by rough terrain. The expected maximum excavation and blasting noise levels at Bonanza caused by construction of the Phase I facilities are shown in Table 5.2-7. Only two blasts per day are normally expected. Noise attenuation by distance, atmospheric absorption, and terrain effects are included in projecting these noise levels. It is also assumed that the blasting noise levels will be limited by regulating the amount of explosives.

Table 5.2-7

PROJECTED MAXIMUM NOISE LEVELS AT BONANZA
CAUSED BY PHASE I CONSTRUCTION

Construction Activities	A-Weighted Sound Level (dBA)	Peak Sound Pressure Level (dB)	Peak Over-Pressure (lb/ft^2)
Excavation, Earth Moving, and Grading of Process Area	40	-	-
Blasting of Process Area and Mining and Ventilation Shafts	-	83	$5.9x10^{-3}$

The expected maximum noise levels are evaluated in terms of the U.S. Environmental Protection Agency (EPA) noise criteria presented in Section 4 of Reference 5-12.

When the predicted A-weighted sound level shown in Table 5.2-7 is compared with EPA criteria, the noise level at Bonanza during the noisiest stage of Phase I construction is estimated to fall within the EPA acceptable range. Similarly, when the peak overpressure of blasting noise is compared with EPA's proposed criteria, this noise is not likely to disturb the residents of Bonanza.

If the noise level were not controlled, exposure to these noise levels during a typical work shift would exceed the operational noise exposure limits specified in the federal and Utah occupational safety and health regulations as described in Section 4 of Environmental Regulations and Guidelines (Ref. 5-12). The impact on personnel will be minimized by adhering closely to the regulations and employing feasible noise control procedures and techniques (see Section 4.2.4).

Operation Noise. On-tract noise impact throughout the project will be limited to personnel working close to machinery and equipment. The noise generated by mining, material handling, and processing is expected to be in excess of 90 dBA in certain areas. Many of these areas are accessed only occasionally during maintenance operations. Activities that can be expected to create high noise levels include mining, crushing and screening, shale loading, retorting, and upgrading. High noise exposure of workers will be limited by regulations and guidelines governing occupational noise exposures (see Section 4 of Ref. 5-12) and subsequent noise control procedures and techniques specific to the facility operation (see Section 4.2.4).

Off-Tract Noise. Off-tract noise during Phase I will be generated by three major sources: the facility construction, the facility operation, and traffic to and from the facility.

Noise generated by construction and operation of the facility itself will be attenuated by distance and atmospheric absorption, and by bluffs and rough terrain that act as natural barriers; all will provide substantial acoustic isolation to nearby communities.

Traffic-generated noise will not be confined to the facility. The impact of traffic noise will depend on traffic volumes, the path of the facility's main access road, and the proximity to nearby communities.

Because of the limited amount of equipment operating during Phase I, noise propagated off tract will not be substantial. Noise from facility operation is expected to be below the background noise levels of 25 to 30 dBA, which are typical of the area and the town of Bonanza.

The main route to and from the facility passes by the community of Bonanza. In predicting traffic noise, personnel access traffic is assumed to originate outside of the town of Bonanza and to pass through it. If all or most of the traffic originates in Bonanza, community planning will be required to minimize the noise impact to the residents.

Traffic noise will be generated by employee car, bus, and truck traffic as well as by supply truck traffic. Employee traffic during construction and operation will be limited mostly to shift changes and possibly lunch breaks. Supply truck traffic will be interspersed throughout the day.

The traffic noise is evaluated in terms of L_{50} (average level) or the noise level exceeded 50 percent of the time. This average level derived from the range of baseline data is estimated to be 30 dBA near the facility and Bonanza. The impact is based on an increase in L_{50} levels at the nearest residence in Bonanza, and the resulting levels are compared with EPA criteria.

Both construction and operation traffic noise levels fall well within the EPA acceptable range. Traffic noise during Phase I construction is expected to increase the ambient L_{50} levels to 38 to 43 dBA.

Traffic noise during Phase I operation is expected to decrease because of reduced traffic volumes. The reduced activity will account for a 10 dB decrease in average noise levels to 28 to 33 dBA at the nearest residence.

5.2.8.2 Phase II

Construction Noise. Approximately 70 workers will be directly involved with

the operation of earth-moving equipment, rock drills, and blasting activities during the noisiest stage of Phase II construction. Noise levels and impacts to those workers are similar to those described for Phase I.

Operation Noise. The number of noise sources during Phase II operations will be significantly greater than Phase I because of increased capacity, additional processing, and associated increase in pieces of equipment. Phase II operation is also expected to expand and intensify areas of excessive occupational noise levels over Phase I. Because of the new equipment and processes employed, a revision of Phase I noise control techniques and procedures may be necessary to limit employee noise exposures.

Off-Tract Noise. The expected maximum excavation and blasting noise levels at Bonanza caused by Phase II construction activities are shown in Table 5.2-8. A comparison of these expected maximum noise levels with EPA criteria shows that no significant noise impact on the residents of Bonanza is expected during Phase II construction.

Facility operation during Phase II will involve a large number of noise sources that will generally increase noise levels (over those of Phase I) near the process area and other parts of the facility. Noise propagated to the off-tract community of Bonanza is expected to increase only marginally. Noise levels at the nearest residence in Bonanza during facility operations are projected to be 25 to 30 dBA, well within the range of measured background levels.

Traffic volumes are expected to peak during this period because of the simultaneous influx of construction and operating personnel and supplies. A projected increase of 18 to 25 dBA above existing L_{50} noise levels is expected at the nearest residence in Bonanza. This increase may be less than indicated, depending on the extent of bus transportation used in lieu of individual passenger cars. Nevertheless, the resulting L_{50} levels of 48 to 53 dBA are low and fall within the EPA acceptable range.

Table 5.2-8

PROJECTED MAXIMUM NOISE LEVELS AT BONANZA
CAUSED BY PHASE II CONSTRUCTION

Construction Activities	A-Weighted Sound Level (dBA)	Peak Sound Pressure Level (dB)	Peak Over-Pressure (lb/ft^2)
Excavation, Earth Moving, and Grading of Process Area	41	-	-
Blasting of Process Area and Mining and Ventilation Shafts	-	96	2.63×10^{-2}

5.2.8.3 Phase III

Construction Noise. Approximately 25 workers will be directly involved with the operation of earth-moving equipment, rock drills, and blasting activities during the noisiest stage of Phase III construction. Noise impacts on these workers are similar to those described for Phase I.

Operation Noise. An increase in the number of noise sources will accompany the increased output capacity of the facility. Noise levels may increase in certain worker areas where the augmented capacity dictates larger concentrations and greater intensities of major noise sources. But since Phase II and III processes are similar, specific noise control strategies and procedures established for Phase II should be readily adaptable to limit employee noise exposures during Phase III.

Off-Tract Noise. The noise level at Bonanza during Phase III construction will be affected by both construction and by Phase II operation. The expected maximum total noise levels under this condition are presented in Table 5.2-9.

Table 5.2-9

PROJECTED MAXIMUM NOISE LEVELS AT BONANZA
DURING PHASE II OPERATION AND PHASE III CONSTRUCTION

Construction Activities	A-Weighted Sound Level (dBA)	Peak Sound Pressure Level (dB)	Peak Over-Pressure (lb/ft^2)
Excavation, Earth Moving, and Grading of Process Area, and Operation of Phase III Facilities	35	-	-
Blasting of Process Area and Mining and Ventilation Shafts	-	86	$8.3x10^{-3}$

When Phase III construction is completed and heavy construction machinery is removed, noise levels will decrease. Levels of 28 to 33 dBA are expected at the nearest residence in Bonanza as a result of Phase III operation. These levels are within or slightly above the range of existing background levels. The facility-generated noise is expected to be barely audible at most and will probably be indistinguishable from the existing ambient level in Bonanza. If surface blasting of rock is necessary, this noise will be perceptible off tract, but will be intermittent.

As the project nears completion, traffic volume and noise caused by construction personnel will decrease. The L_{50} levels of 29 to 34 dBA projected at the nearest residence in Bonanza are a result of traffic noise during the full-scale Phase III operation. These lvels are well below the EPA recommended levels of 55 dBA (L_{dn}) to protect the public health and welfare.

5.2.8.4 All Phases: Noise Effects on Wildlife

Auditory sensing (perception of ground vibration and airborne sound) and visual and olfactory sensing are necessary for wildlife survival. It is

difficult to determine the degree to which noise contributes to wildlife disruption, since it varies considerably among wildlife species.

Noise effects on wildlife fall into two categories: 1) migration of noise-sensitive to species to quieter areas, and 2) acclimatization of wildlife to the higher noise environments.

Initial wildlife disruption is not, in the strictest sense, a noise effect. The sound from construction, operation, and transportation activities of the proposed facilities is perceived by wildlife as warning information; noise is defined as unwanted sound that hampers the transfer of information. Nonetheless, the effects of noise from the project can be expected to combine with visual and olfactory evidence of the increased presence of humans to displace wildlife from current habitats. Little reliable information is currently available to document the expected extent of such specific noise-induced disruption upon wildlife around Tracts Ua and Ub.

Numerous observations, however, have been documented on the ability of many wildlife species to adjust to noisier areas. Typical examples are flocks of birds at noisy refuse disposal areas, at airports, and at rocket-testing grounds, and the occurrence of deer and other wildlife in some urban areas.

FLARE HEADER DESIGN BASIS

The flare header system design will be carried out on the following basis:

(a). Discharges from processing plant safety valves relieving during various emergencies or upset conditions are handled by a low and a high pressure system. The justification for a separate low pressure (LP) and high pressure (HP) system will be arrived at because of the wide range of pressure relief valve set pressures (approximately in the order of 40:1) in the various process units. The requirement for a low, high, or both flare headers in a particular process unit will be dictated by carefully examining the hydraulics and considering the most reasonable piping cost.

(b) Each flare gas collection header (low or high) will be sized based on the combined flow caused by a single unit contingency, i.e., unit power failure, unit instrument air failure, etc. A total plant contingency will be considered, but not accepted. In case of fire, relief loads for piping design will be calculated based on vessels involved in a fire risk area having a radius of approximately 40 ft.

(c) The maximum allowable builtup back pressure on conventional and balanced type type pressure relief valves will be limited to 10 and 40% of their set pressures, respectively.

(d) The maximum allowable working pressure in the main low pressure flare header will be limited to 18 psig. This was arrived at by identifying the pressure relief valve with the lower set pressure in all the process units and using balanced type PSVs for this application. Thus by using balanced type

pressure relief valves for protecting low pressure column with one of the valves set at 45 psig (lowest set pressure), the maximum builtup back pressure allowed was 18 psig (0.4 x 45 = 18 psig). Also for the high pressure flare header, the maximum allowable working pressure was limited to 50 psig to keep the design pressure of the piping as well as the associated equipment to a minimum.

(e) Conventional relief valves will be used for:

(i) PSVs having a set pressure higher than 500 psig and relieving into high pressure flare header, or

(ii) PSVs having a set pressure higher than 180 psig and relieving into low pressure flare header.

In all other cases balanced bellows type pressure relief valves will be used.

(f) Pressure relief valves in critical service will be spared by using a trans-flow valve.

(g) The relief manifolds will be sized based on the maximum allowable back pressure on the pressure relief valve in question. To avoid fatigue failure of relief valve discharge piping, the maximum flow velocity through most of the headers and subheaders will be limited to Mach 0.5.

(h) Car sealed open block valves will be provided at the battery limit of each process unit in order to isolate any one or more of the process units with all other units operating normally. No block valves will be provided in individual reaction train HP flare headers.

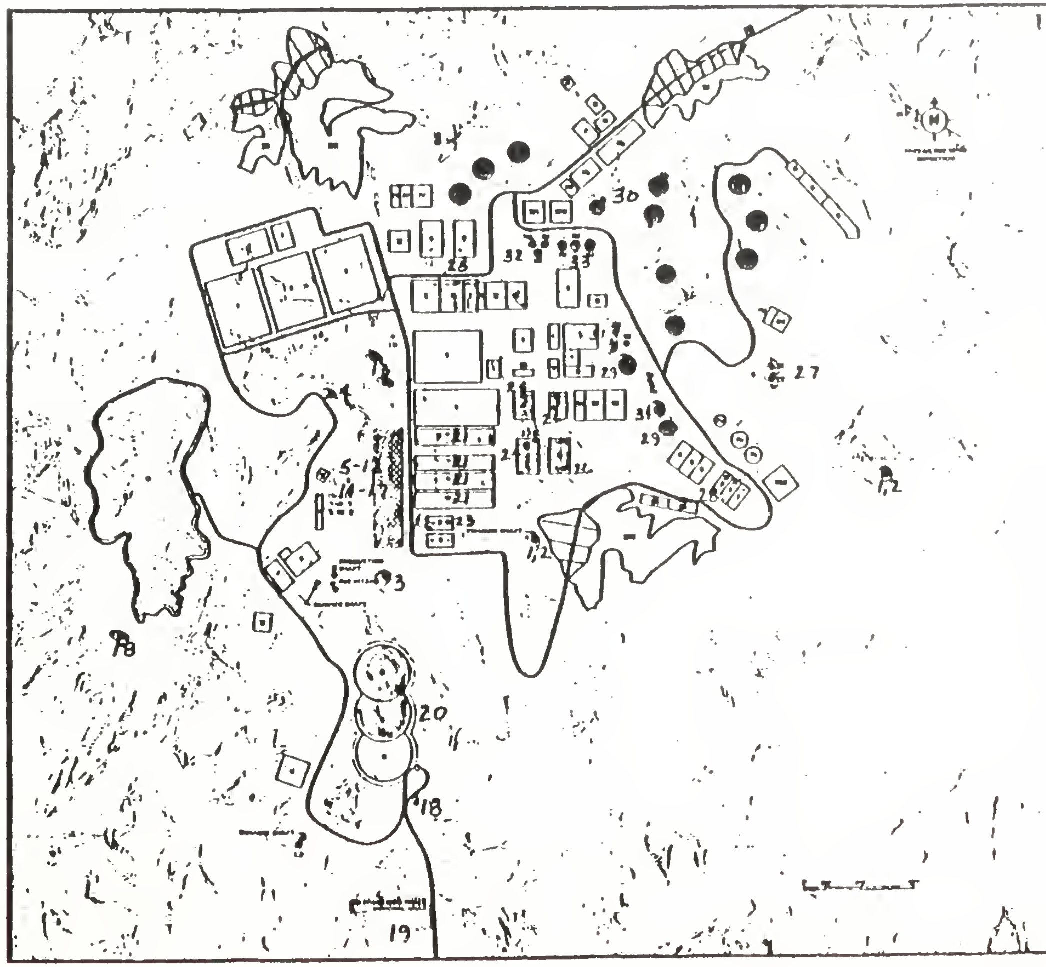
(i) Emergency depressuring facilities will be provided in all process units operating at high pressures and temperatures to reduce the pressure in the equipment to safe levels during overpressurization during various contingencies.

(j) In determining the relief loads during fire, no credit will be taken for the vessel insulation.

(k) All low and high pressure process flare headers will be provided with gas inlets for continuous purging. Flow restrictive orifices will be installed on all thse gas inlets to conserve refinery fuel gas. However, an alternative purge gas connection will be provided upstream of the flare knockout drum for emergency purposes.

EMISSION POINTS:

1 MINING
2 IN MINE CRUSHING
3 MINE CONVEYOR SURGE BIN
4 MINE CONVEYOR TRANSFER POINTS
5 FEED TO PHASE I AND II STORAGE SILOS
6 PHASE I AND II SURFACE CRUSHING AND SCREENING
7 FINES CONVEYOR FEED (PHASE I AND II CONVEYORS)
8 FINES CONVEYOR TRANSFER POINTS (PHASE I AND II SECTIONS)
9 TOSCO II RETORT FEED BINS
10 UNION B CONVEYOR FEED
11 UNION B RETORT FEED BINS
12 SUPERIOR CONVEYOR FEED (PHASES I AND II)
13 SUPERIOR RETORT FEED BINS
14 UNION B DISCHARGE TO PROCESSED SHALE CONVEYOR
15 TOSCO II DISCHARGE TO PROCESSED SHALE CONVEYOR
16 SUPERIOR (PHASE I) DISCHARGE TO PROCESSED SHALE CONVEYOR
17 SUPERIOR (PHASE II) DISCHARGE TO PROCESSED SHALE CONVEYOR/
18 PROCESSED SHALE CONVEYOR TRANSFER POINTS
19 PROCESSED SHALE STORAGE
20 EMERGENCY STOCKPILE
21 UNION B RECYCLE GAS HEATERS
22 TOSCO II BALL HEATERS AND LIFT PIPES
23 TOSCO II ELUTRIATORS AND PROCESSED SHALE MOISTURIZERS
24 HYDROGEN PLANT REFORMER FURNACE (PHASES I, II)
25 BOILER AND POWER PLANT (PHASES I, II)
26 HYDROTREATER (PHASES I, II)
27 FLARE PILOT
28 GAS TREATMENT PLANT (PHASES I, II)
29 RAW SHALE OIL STORAGE
30 PRODUCT OIL STORAGE
31 RECOVERED OIL (SLOP) TANKS
32 DIESEL FUEL TANKS
33 FUEL OIL TANKS
34 NAPHTHA STORAGE



EMISSION POINTS PLOT PLAN, PHASE II

ATTACHMENT NO. 6

WHITE RIVER SHALE OIL CORPORATION
SUITE 500 PRUDENTIAL BUILDING, 115 SOUTH MAIN STREET
SALT LAKE CITY, UTAH 84111
(801) 363-1170

November 10, 1981

RECEIVED

NOV 13 1981
OFFICE OF
AREA OIL SHALE SUPERVISOR
U.S. G.S.

Mr. Peter A. Rutledge
Deputy Conservation Manager - Oil Shale
Oil Shale Office
131 North 6th Street, Suite 300
Grand Junction, Colorado 81501

Dear Mr. Rutledge,

This letter will supplement information provided to your office on October 20, 1981 in response to your request for additional information concerning the Detailed Development Plan for White River Shale Project.

Specifically attached are the following items;

1) A more detailed capital and operating cost estimate for each phase of the project is included as Attachment No. 1. This material should be handled as confidential.
2) More detailed information on the status of oil and gas well leases on Tracts Ua and Ub is included as Attachment No. 2. Contrary to the number mentioned in the DDP, there appear to be only 7 oil and gas wells drilled on-tract.

Please advise if you have any questions concerning this information.

Sincerely,

James W. Godlove

JAMES W. GODLOVE
Director of Environmental Affairs

JWG:mw
Enclosures

f102056

FIELD & WELL NO.	LOCATION	COMPLETION STATUS	OWNERSHIP-FEDERAL LEASES	STATUS OF LEASE
Watson Field (Cont.)		The well was plugged on September 5, in the following manner: Plug at 1000-1105' with 33 sax cement; plug from 202 to bottom of surface pipe at 240 feet with 12 sax cement. Halliburton plug set at 60' and 60' cement set in top of surface pipe. Well location marked by piece 4" drill pipe extending 6' above ground and marked with well name and location.		
Undesignated Field #5	363' FSL & 1726 FEL of Sec. 28, SE¼SW¼SE¼, T10S R24E, SL Mer., Uintah County, Utah	No production; plugged and abandoned 7/61; TD 7050' Plug and abandon as per Sundry Notice dated 4/20/61. Salvaged wellhead equipment, set plug from 25 ft. to ground level in 5 1/2" (note cement was circulated during the primary cement job on the 7 5/8" intermediate casing string). Set iron marker 4'x4" from ground level. Back filled cellar to ground level.	Lessee: Gulf Oil & El Paso Nat. Gas Company Operator: El Paso Nautral Gas Company	Terminated 2/26/70
Southam Cyn. Field #4	797' FNL & 839' FEL of Sec. 29, SW¼NE¼NE¼, T10S R24E, SL Mer., Uintah County, Utah	Initial production 4,700 MCFGPD & 121 B. Plugged and abandoned 2/71; TD 6030'. 4/18/70 Moved in, rigged up, and work tubing. 4/19/70 Pulled tubing. 4/20/70 Ran tubing and spotted 10 sx. cement plug across perfs. 5946-66'. Pulled tubing. 4/21/70 Worked 7", shot 7" off @ 2987', worked free. Started laying down 7" casing. 4/22/70 Laying down 7" casing. 4/23/70 Finished laying down 7" casing. 4/24/70 Ran tubing and pumped plugs as follows: 35 sx. 2985' 35 sx. 700'	Orig. Lessee: El Paso Nat. Gas Later Lessee: Shell Oil, et al Operator: Consolidated Oil & Gas	Terminated 3/20/70

FIELD & WELL NO.	LOCATION	COMPLETION STATUS	OWNERSHIP-FEDERAL LEASES	STATUS OF LEASE
(Southam Cyn. Field #4 Cont.)		35 sx. 1500' 70 sx. in/out plug bottom surface casing (445'). 4/25/70 Erected dry hole marker and set with 10 sx. cement. (Pulled and recovered 2987' of 7" casing.)		
Wildcat #6	2022' FSL & 890' FEL of Sec. 30, NE¼NE¼SE¼, T10S R24E, SL Mer., Uintah County, Utah	No production; plugged & abandoned 7/62; TD 7082" 7-21-60: This well was plugged and abandoned with the following plugs: Plug #1 Top of Castlegate 7015'-6938' w/35/sxs. Plug #2 Top of Mesaverde 4720'-4643' w/25 sxs. Plug #3 Top of Wasatch 3030'-2953' w/25 sxs. Plug #4 Water flow 1600'-1523' w/25 sex. Plug #5 Bottom of surface casing 290'-235' w/25 sxs. Plug $6 15'-surface w/25 sxs. Stripped off Bradenhead and placed 4"x4' P&A marker over well bore.	Lessee: Gulf Oil & El Paso Nat. Gas. Operator: El Paso Nat. Gas	Terminated 2/26/70
Wildcat Gem #2	1580' FSL and 1890' FEL of Sec. 18, S½NW¼SE¼, T10S, R25E, SL Mer., Uintah County, Utah	No production; plugged and abandoned 5/63; TD 6509' Placed 20 sacks neat cement in 6-3/4" hole @ 4000' Placed 30 sacks neat cement in 9-5/8" hole @ 1950' Placed 20 sacks neat cement in 10-3/4" pipe @ 226' Placed 10 sacks @ top of Marker Location cleaned and marker affixed.	Lessee: El Paso Nat. Gas Co. & Gulf Oil Corporation Operator: Moab Drilling Co.	Terminated 2/1/66

ATTACHMENT NO. 2

OIL AND GAS WELLS ON TRACTS Ua &

FIELD AND WELL NO.	LOCATION	COMPLETION STATUS
latson Field #2	350' FSL and 660' FWL of Sec. 14, S SW¼SW¼, T10S, R24E, SL Mer., Uintah County, Utah	No production; plugged & aband TD 3315' Well was plugged October 12, 19 ing manner: Set 225 sax cement Set 20 sax cement from 140-205 Halliburton plug. Set 10 sax c on top of Halliburton plug. At pipe (4") with description of w through plate on top of surface mately 6 feet of this pipe is e cement at the top of the surfac
Southam Cyn. Field Gem #1	2298' FSL & 2079' FWL of sec. 22, NE¼NE¼SW¼, T10S R24E, SL Mer., Uintah County, Utah	Completed for production 1/30/6 Initial production-1,200,000 AOI TD 6160' PB 3407" Per Bob Martins of USGS-SLC, the in but could not be successfully $18,000 was spent in Aug. 1981 to p bond was for $10,000; it was loaded w water and well head and valves installe still a gas well.
latson Field #1	2535' FNL and 515 FWL of Sec. 24, S SW¼NW¼, T10S, R24E, SL Mer., Uintah County, Utah	No production; plugged and abandoned 11/52; TD 4249'

ated 8/30/54

CONFIDENTIAL

COST INFORMATION

TWO SHEETS

SEE CONFIDENTIAL FILE

IF YOU NEED TO SEE

THE INFORMATION

WRSP DDP

SUPPLEMENTAL MATERIAL

PER

DECEMBER 4, 1981 REQUEST

United States Department of the Interior

GEOLOGICAL SURVEY

Conservation Division
Area Oil Shale Supervisor's Office
131 N 6th, Suite 300
Grand Junction, Colorado 81501

December 4, 1981

Mr. James W. Godlove
Director of Environmental Affairs
White River Shale Oil Corporation
Suite 500, Prudential Building
115 South Main Street
Salt Lake City, UT 84111

Dear Mr. Godlove:

The OSO staff has completed an in-depth review of both the White River Shale Project's Detailed Development Plan (DDP) and the public comment letters. The staff met on December 2, 1981, to discuss the issues and concerns to determine the supplemental information to deem the DDP complete.

Based on our review and meeting, the following supplemental information is requested and will become part of the White River Shale Project DDP:

1) Provide information on the oil shale source used to obtain the data in Tables 3.7-1,2,3,5, and 7.

2) Provide energy and material balance data on each of the retorting processes. Information on the source of raw shale fed into the retorts from which the energy and material balance data were obtained should be included. The material balances should include sulfur and nitrogen balances.

3) Add a column on Table 4.2-1, EPA New Source Performance Standards, that shows the specific equipment or processes expected to be subject to NSPS.

4) Please commit to the submission of a detailed Monitoring Manual by March 1, 1982.

5) Clarify your intentions on the use of chemical wetting agents or dust suppressants for processed shale disposal. In section 3.10.3.3 you stated that a wetting agent will be used if it proves effective from operating experience, yet in section 7.10.4.4, you state chemical wetting agents will be "used only if necessary." The implications of these two statments are contradictory. In view of the fact that your air pollution control plan, as shown in Tables 4.2-4 through 6,

specifies the use of chemical dust suppressants and takes credit for 85% control efficiency for that use you, therefore, should be more positive in your statement of its use.

6) Provide a discussion of the sulfur species present other than H_2S and SO_2 and the implications of these compounds for your chosen sulfur control technology. Specifically, what species and amounts may be present in the low-BTU gas and are these completely oxidized in incineration or firing in a boiler? What species and amounts may be present in the high-BTU gas? Follow the high-BTU gas streams, discuss the species and amounts, and final fate of the compounds in the H_2S stripping stream, the MDEA adsorber, acid gas streams, and the Claus and SCOT process units.

7) Submit a revised schedule with as much detail as possible in view of conflicts between Figure 3.3-2 in the DDP and permit schedule as attachment in the 10/20/81 supplemental material.

8) A pillar should be shown under the westerly decline on figure 3.5-5.

9) Phase I processed shale plan is not sufficiently detailed to evaluate the experimental design. Lessee needs to commit to submission for approval of the final detailed design prior to initial development of processed shale disposal area.

10) Should not the ventilation be reversed in figure 3.7-7? Provide a schematic for primary ventilation of Phases II & III.

11) Consideration should be given to disposal of fines from the dust collectors on the surface rather than underground to eliminate the possibility of spontaneous combustion in the mine.

12) Need better clarification of the seven existing gas wells on tracts. Gem #1 is apparently within the Phase I mine area. These holes will have to be re-entered to assure proper plugging before mining can advance through them or sufficient pillar will have to be left surrounding them.

13) Clarification in the stocking rate of two allotments in Table 5.4-1. Also need clarification or verification of AUM's given on pages 5-60-61.

14) Need a rewrite of endangered species section to give accurate account of threatened and endangered species as well as plant species listed for review.

15) Need a commitment that all plant growth medium or topsoil-like material and nontoxic sludge will be used for revegetation purposes.

16) 3.3.19 - What is NPDES and state discharge permit for?

17) 3.5.1.1, p. 45, para. 1 - OSO assumes no surface discharge will occur during shaft sinking. Is this correct?

18) 3.5.5, p. 3-63 - What is the quality of mine water? Does lessee have any plans to treat-use-reinject such excess mine water? Will construction of holding pond (3.19.2) be completed prior to shaft sinking encountering the Bird's Nest Aquifer?

19) 3.6.2.3, p. 3-70 - What measures will lessee take to protect raw shale piles from leaching and spontaneous combustion? What will be the nature of the impervious layer (p. 4-91)?

20) Several questions as to water rights have arisen. Lessee needs to submit their plans for water supply?

21) 3.11.3, p. 3-126 - Did lessee consider the potential for degradable waste beneath/in the retorted shale pile to lead to instability of the pile?

22) 4.4.1, p. 4-71, para. 1; 4.5.1, p. 480 - Can OSO assume that lessee's use of words "contamination," "pollution," and "degradation" is that of McKee and Wolf?

23) 4.4.1.2, p. 4-71 - What duration is the 100-year storm? What is the source for the 100-year storm data on p. 4-88 (2 inches in 24 hours)?

24) 4.4.3.3, p. 4-77 - What amount of precipitation does lessee assume for tankage design?

25) 4.5.2, p. 4-83 - What permeability range does the lessee consider to be "impervious"?

26) 4.5.3, p. 4-94 - What basis for considering subsidence to be uniform? Plant pillar, topography, boundaries will tend to cause non-uniform subsidence.

27) 4.6.2.2, p. 4-104,5 - What is the source of data for the "24 inch no-migration" statement?

28) 4.6.2.5, p. 4-112 - What data supports statement that "D" soils are salty below 44 inches in depth?

29) 4.13.3.1, p. 4-167,8,9 - Can OSO assume that these drawings and the test are schematic or conceptual only?

30) 7.10.5.3, p. 7-56 - Explain data and testing to examine the expected "fully impervious barrier" formed by the Uinta Formation. OSO assumes "impervious" only applies when the permeability is in the range of 10-6 Darcey. Waiting for lysimeter tests to determine if a liner

for the processed shale is needed indicates that the pile will be started without a liner. If a liner is proven necessary, what actions would be taken to prevent leaching of the pile already started?

31) There is a discrepancy between the 73% recovery rate in the confidential data report and the 63% overall recovery including the shaft/plant pillar in the 100% of resource.

32) Lessee will commit to a detailed Spill Prevention Control and Contingency Plan and will consider P.L. 96-510 in its preparation.

33) Ground water flow will be towards the White River along the structural dip. What long-term water quality effects might be expected as a result of ground water flow through the mine to the river? Need discussion on reservoir seepage to mine and mining effects on the integrity of reservoir.

34) What is the Vernal-to-tract and Craig-to-tract highway mileage, load class, and safe traffic density?

35) What is WRSP's commitment to mass transit from potential bedroom communities and from on-tract housing?

36) What is the unused pumping capacity in existing common carrier pipelines that WRSP might seek to transport early production?

37) How many tank truck loads will be made in Phase I and over what roads?

Your response to these concerns and questions will be filed in our office and will be available for public inspection as part of the WRSP DDP.

Please call if you have any questions concerning the above requested information.

Sincerely,

Peter A. Rutledge
Deputy Conservation Manager
Oil Shale

Received
DCM-OS
JAN 7 1982

WHITE RIVER SHALE PROJECT

WRSP

100 WEST WALNUT STREET
PASADENA, CALIFORNIA 91124
(213) 440-6580
Telex: WH: 675-336

December 31, 1981

Mr. Peter A. Rutledge
Deputy Conservation Manager
Oil Shale Office
131 N. 6th Street, Suite 300
Grand Junction, Colorado 81501

Dear Pete:

Further to your letter of December 4 and Jim Godlove's response letter to you of December 21, attached are two copies of our most recent Master Schedule for WRSP Phase I. (SCH-00-PR-1-1, and SCH-00-PR-1-2) This should satisfy Item (7) in the above-mentioned letters.

Phase II and III schedules from Figure 3.3-1 of the DDP would fit on the end of the above Phase I schedule. We will keep you informed of significant schedule changes as our project proceeds.

Very truly yours,

WHITE RIVER SHALE OIL CORPORATION

B Page

Lowell B. Page
Manager of Mining

LBP:pm

encl.

cc: C. E. Doney
J. W. Godlove

E&C0010

WHITE RIVER SHALE OIL CORPORATION

SUITE 500 PRUDENTIAL BUILDING, 115 SOUTH MAIN STREET
SALT LAKE CITY, UTAH 84111
(801) 363-1170

December 21, 1981

Mr. Peter A. Rutledge
Deputy Conservation Manager
Oil Shale Office
131 N. 6th Street, Suite 300
Grand Junction, Colorado 81501

Dear Mr. Rutledge,

Your letter of December 4, 1981 requested additional information concerning the White River Shale Project (WRSP) Detailed Development Plan. Attached to this letter are responses to the issues and concerns raised in your letter.

In addition to your list of concerns, the White River Shale Oil Corporation wishes to discuss its plans for socio-economic monitoring in conjunction with development of the WRSP. As you are aware, the leases to Ua and Ub do not require the lessees to address socio-economic issues. We recognize however, the importance of evaluating such issues. We have recently prepared a "Community and Infrastructure Support Study" that discusses in great detail the employment and population projections for our project.

We consider this study to be an important data source for continuing discussions with various state and local agencies concerning planning for growth in the area of our planned operations. Necessary mitigation actions, and the role White River will play, will be developed through these planning activities with the respective community governments.

White River will, however, also be conducting a direct employee monitoring program. Plans for this program have not been developed. In general, it will consist of maintaining up to date records on the number of employees, location of residence, length of residence, type of residence, type of employment (e.g., construction versus operating), family status, and length of employment on the project.

This information will be made available to the Oil Shale Office and others on a regular basis. We expect the data to be useful to state and local agencies as we jointly develop plans for, and measure the performance of, our collective social impact mitigation efforts.

We look forward to the completion of your review and approval of our plan to develop Tracts Ua and Ub. Please contact me if you have questions concerning this letter.

Sincerely,

JAMES W. GODLOVE
Director of Environmental Affairs

JWG:mrw

WHITE RIVER SHALE OIL CORPORATION
RESPONSE TO OIL SHALE OFFICE
REQUEST FOR SUPPLEMENTAL INFORMATION
ON DETAILED DEVELOPMENT PLAN

The following respond to questions raised by the Oil Shale Office letter of December 4, 1981 relative to the White River Shale Project Detailed Development Plan. The numbers in parenthesis refer to the question number listed in the OSO letter.

(1) Question: Provide information on the oil shale source used to obtain the data in Tables 3.7-1,2,3,5 and 7.

Answer: Table 3.7-1 is a hypothetical material balance based upon our expectations for the Utah Oil Shale to be retorted. Tables 3.7-2 and 3.7-3 for the Superior retort are based upon Utah oil shale. Tables 3.7-4 and 3.7-5 for the Union retort are also based upon Utah oil shale. Tables 3.7-6 and 3.7-7 for the TOSCO retort are based upon Colorado oil shale.

(2) Question: Provide energy and material balance data on each of the retorting processes. Information on the source of raw shale fed into the retorts from which the energy and material balance data were obtained should be included. The material balances should include sulfur and nitrogen balances.

Answer: This information was not available at DDP publication. Since then preliminary licensing and/or disclosure agreements have been made with both Superior and Union. At present a series of tests on Hells' Hole shale are underway at Superiors' Denver pilot plant and 200 tons of the same shale has been shipped to Unions' pilot plant at Brea, California. Data from these tests is to be used in Licensor's process design for both retorts. This information will be available to the Oil Shale Office on a confidential basis.

(3) Question: Add a column on Table 4.2-1, EPA New Source Performance Standards, that shows the specific equipment or processes expected to be subject to NSPS.

Answer: Attachment No. 1 is a revised copy of Table 4.2-1 showing the specific project units subject to the New Source Performance Standards.

(4) Question: Please commit to the submission of a detailed monitoring manual by March 1, 1982.

Answer: As mentioned in Section 6.1.5 of the DDP, a detailed field environmental monitoring manual will be prepared for WRSP. The scope of our future monitoring program to be described in the manual will be similar to the scope discussed in Section 6 of the DDP. However, the manual will include much greater detail on the rationale of parameter and monitoring site selection, sampling methods, data management and analysis and our contingency plans when non-baseline conditions are detected. Our approach will be statistically based using our knowledge of the ecosystem of Tracts Ua and Ub. All sections of the manual are currently in preparation. A final draft manual will be available and submitted for review to the OSO prior to March 1, 1982.

(5) Question: Clarify your intentions on the use of chemical wetting agents or dust suppressants for processed shale disposal. In section 3.10.3.3 you stated that a wetting agent will be used if it proves effective from operating experience, yet in section 7.10.4.4, you state chemical wetting agents will be "used only if necessary". The implications of these two statements are contradictory. In view of the fact that your air pollution control plan, as shown in Tables 4.2-4 through 6, specifies the use of chemical dust suppressants and takes credit for 85% control efficiency for that use, you therefore, should be more positive in your statement of its use.

Answer: The WRSP will be constructed and operated in a manner which minimizes the generation of dust. Given this commitment, there was no intended conflict between the control procedures specified in Sections 7.10.4.4 and 3.10.3.3. Sections 4.2.3.1 and 4.2.3.2 provide the actual plans for protecting the environment through dust control procedures.

It is the WRSP plan to use water alone as our primary means of limiting dust. However, should conditions arise wherein the required water consumption rates become excessive or the effectiveness of unsupplemented water applications is diminished then the use of chemical wetting agents will be deemed necessary.

It is also the WRSP intent to operate the project in compliance with the emission rates identified in the DDP and Prevention of Significant Deterioration permit application. The 85 percent efficiency level expressed in the emission inventory tables in Section 4.2 for various controlled dust sources may be attainable with water in the absence of wetting agents. Operational experience is needed to evaluate the effectiveness of water-only treatment.

Chemical wetting agents will be used during conditions that reduce the effectiveness of water-only. However, the use of wetting agents will not increase the maximum control efficiency (85%), but will assist in maintaining that level during adverse conditions.

Also, it should be noted that in certain instances (e.g., wind erosion) a combination of measures is actually responsible for the total degree of control. These include use of a canyon for the disposal site, proper compaction of the disturbed surface or processed shale, revegetation of the disturbed area or completed portion of the processed shale pile as quickly as possible. Each of these measures, in addition to water and/or wetting agents, contribute to our overall suppression of dust.

(6) Question: Provide a discussion of the sulfur species present other than H_2S and SO_2 and the implications of these compounds for your chosen sulfur control technology. Specifically, what species and amounts may be present in the low-BTU gas and are these completely oxidized in incineration or firing in a boiler? What species and amounts may be present in the high-BTU gas? Follow the high-BTU gas streams discuss the species and amounts and final fate of the compounds in the H_2S stripping stream, the MDEA adsorber, acid gas streams and the Claus and SCOT process units.

Answer: In addition to the presence of hydrogen sulfide and sulfur dioxide in the high- and low-btu gases, other sulfur species may be expected to occur in unknown amounts. These species include thiosulfites, carbonyl sulfide, carbon disulfide, methyl mercaptan, ethyl mercaptan, higher mercaptans and other miscellaneous organic sulfur compounds of unidentified formula and structure. Information contained in the DDP and the PSD application is our best estimate at this time of the resultant emissions to the atmosphere. Much more information is needed to improve these estimates.

Concerning the various gas treating process units, the MDEA absorber will remove only hydrogen sulfide. Measurable removal of other sulfur species cannot be expected. The resultant gas stream will be composed of hydrogen sulfide and carbon dioxide, with possible trace quantities of other sulfur compounds. The gas will go to the Claus/SCOT plant.

The feed to the Claus/SCOT plant will be acid gas from the MDEA stripper and hydrogen sulfide from the WWT plant. The acid gas may have trace quantities of other sulfur compounds. The WWT plant gas stream will have none. None of the sulfur compounds will survive treatment in the Claus/SCOT process.

In the treated high-btu gas streams to the hydrogen plant, all sulfur compounds will be converted to hydrogen sulfide by means of hydro-treating over a cobalt-molybdenum catalyst. This material will be removed by MDEA absorption and sent to the Claus/SCOT plant.

Of the high-btu gas used as fuel, all mercaptans above methyl mercaptan will condense out in the C5 plus recovery system. All other sulfur componds will pass through the MDEA absorber and will be present in the fuel gas. It is expected that these sulfur compounds will be completely converted to sulfur dioxide in the furnaces.

At this time, White River and Parsons are reviewing the gas treating requirements for the Superior retort offgas. Particular emphasis is being placed on the determination of sulfur species in the offgas and the treatment system most likely to remove sulfur species to a level compatible with the PSD application.

The gas treating requirements for Union offgases will be similarly reviewed when White River receives a detailed analysis of the quality and quantity of these gases from Union Oil Company.

The findings of these studies and the resultant gas treating design will be reviewed with the OSO prior to surface treating facility construction.

(7) Question: Submit a revised schedule with as much detail as possible in view of conflicts between Figure 3.3-2 in the DDP and permit schedule as attachment in the 10/20/81 supplemental material.

Answer: Revised Master Project Schedules are now being finalized for WRSP. Copies will be forwarded to OSO by December 23, 1981.

(8) Question: A pillar should be shown under the westerly decline on figure 3.5-5.

Answer: In the WRSP supplemental material submitted to the OSO on October 20, 1981 a revised Figure 3.5-5 was provided showing a pillar beneath the toe of the westerly decline. It is our intention to properly support the decline.

(9) Question: Phase I processed shale plan is not sufficiently detailed to evaluate the experimental design. Lessee needs to commit to submission for approval of the final detailed design prior to initial development of processed shale disposal area.

Answer: White River has been conducting applied research on the disposal and reclamation of processed shale since 1975 under the direction of Dr. Cy McKell formerly with Utah State University and now Vice President of Research for Nature Plants, Salt Lake City. Although the information developed from these studies provide substantial support for our ability to reclaim the processed shale disposal area, White River is aware that additional study of various shale disposal concepts and a refinement of our revegetation approach is needed.

White River will establish a processed shale disposal research plot near the Phase I disposal area to fully evaluate the environmental effects of our disposal and reclamation plan. Results from this study will guide our long-range disposal activities.

Further White River will also provide to the OSO a detailed design of our Phase I processed shale disposal area at least nine months prior to initial development of the area. Parsons (our detailed design contractor) has begun to identify the concerns associated with processed shale disposal. The environmental criteria which will, in part, guide the design of the disposal area, will be established during the first quarter of 1982. When complete, the design will be reviewed with the OSO for approval.

(10) Question: Should not the ventilation be reversed in figure 3.5-7? Provide a schematic for primary ventilation of Phases II and III.

Answer: Attachment No. 2 is a revised copy of Figure 3.5-7 showing our typical mine panel ventilation plan. White River is proceeding with a detailed ventilation study for all three phases of the project. The first portion of the study should be completed in January, 1982 and it will be reviewed with the OSO at that time.

(11) Question: Consideration should be given to disposal of fines from the dust collectors on the surface rather than underground to eliminate the possibility of spontaneous combustion in the mine.

Answer: Our present design basis will provide facilities so that fines from the underground dust collectors in the crushing

station area may be redeposited on the conveyor belts and ultimately hoisted to the surface. The design will include proper consideration of the particulate emission potential of surface disposal. Also, a study is underway to evaluate the cost and efficiency of wet versus dry dust collection systems for underground use.

(12) Question: Need better clarification of the seven existing gas wells on tracts. Gem #1 is apparently within the Phase I mine area. These holes will have to be re-entered to assure proper plugging before mining can advance through them or sufficient pillar will have to be left surrounding them.

Answer: As discussed in our letter of October 20, 1981, the correct number of gas wells on Ua and Ub is seven of which six have been plugged and abandoned. The open well is just to the west of the proposed plant site and is cased and valved at the surface. Of the six plugged wells, we will investigate fully the abandonment report on each. If abandonment procedure appears unsatisfactory, we may elect to re-enter the well(s) and complete abandonment. In any case, WRSP will not mine through any of these wells, but will plan to leave them within the regular pillars of our mine plan. With regard to Gem #1 (the capped well near the plant site), our first option would be to obtain rights to this gas and produce the well to supply part of the gas requirements for the project. However, if this is not feasible, the well will be plugged and left within a mine pillar.

(13) Question: Clarification in the stocking rate of two allotments in Table 5.4-1. Also need clarification or verification of AUM's given on pages 5-60-61.

Answer: The paragraph on page 5-60 concerning Livestock should read as follows,

"As a result of the project approximately 2,945 acres of sheep-grazing land will be removed from Southam and Wagon Hound Allotments, some temporarily and other areas permanently (see Figure 2.5-7). As shown in Table 5.4-1, this represents a loss of approximately 822 animal unit months (AUM), or approximately a 13 percent reduction in current grazing levels on the two grazing allotments."

Also, Table 5.4-1 should be revised as follows:

TABLE 5.4-1

Grazing Utilization

Grazing Allotment	Current Acreage	Acreage(b) Lost	Current(c) AUM	AUM Lost	Percent Loss
Southam Canyon - Little Emma	12,239	2,475	3,231	652	20.2
Wagon Hound-Rabbit Mtn.	8,584	470	3,089	170	5.5
Total	20,823	2,945	6,320	822	

a) All numbers are approximmate
b) Depending on the rate of revegetation of the processed shale, this will not represent a permanent loss.
c) Current Bureau of Land Management data.

(14) Question: Need a rewrite of endangered species section to give accurate account of threatened and endangered species as well as plant species listed for review.

Answer: Concerning threatened and endangered species the following changes should be made to the DDP.

(a) Page 1-16 (4th paragraph). Should say only that "One threatened plant species has been reported in the region, Sclerocactus glaucus. However, this species has not been observed on tract."
(b) Page 2-149 (paragraph 2.5.1.4). Add the sentence, "Sclerocactus glaucus is a threatened species in the region but is usually found in Green River shale formations whereas the soil of Tracts Ua and Ub are primarily from Uinta Formation."
(c) Page 2-149 (paragraph 2.5.1.4). Change the fifth sentence to read, "Additionally for two other species there is enough information to support their status as threatened or endangered, but they have yet to be listed; namely, Cryptantha barnebyi and Glaucocarpum suffrustescens. Four species are considered sensitive and are under review but biological information is lacking; namely, Aquilegia barnebyi, Astragalus lustosus, Festuca dasyclada, and Penstemon grahamii. One other species is no longer under review, Eriogonum hylophilam. All of these species are found in the Green River Formation.
(d) Page 5-67 (paragraph 5.4.2.9 Plants). The fourth sentence should read, "Cryptantha barnebyi, Glaucocarpum suffrutescens, Aquilegia barnebyi, Astragalus lutosus, Festuca dasyclada and Penstemon grahamii are found in

vegetation types similar to those found on the tracts but in soils of different origin."

(15) Question: Need a commitment that all plant growth medium or topsoil-like material and nontoxic sludge will be used for revegetation purposes.

Answer: Soil studies conducted by White River during the Baseline program identified only limited quantities of useable topsoil-like material. Thus, our reclamation philosophy (and the applied research) was directed at maximum beneficial use of this limited resource in a "topsoil trench" operation. White River is encouraged by the results of its processed shale reclamation studies in a limited soil environment. However, continued long-term study is necessary to confirm the amount of soil required for successful processed shale revegetation.

Thus, White River agrees to recover, stockpile and reuse all suitable topsoil-like material in the processed shale reclamation program during Phase I. This also includes the beneficial use of acceptable project sludges. However, before entering the commercial phase of the project White River will reevaluate this costly practice in light of information collected during Phase I.

(16) Question: What is NPDES and state discharge permit for?

Answer: Although our current plans project no discharge of wastewaters to any receiving stream, there is the possibility that circumstances could develop which would lead to an unexpected release. This would occur if the 100 year storm design frequency were exceeded or if successive large rainstorms occurred resulting in a discharge from the water retention ponds. It is upon these premises that an NPDES and a Utah Bureau of Water Pollution Control permit to discharge application will be submitted.

(17) Question: 3.5.1.1, p. 45, para. 1 - CSO assumes no surface discharge will occur during shaft sinking. Is this correct?

Answer: White River does not plan to discharge any water from the shaft sinking operation to the White River. Any water pumped in the course of shaft sinking will be contained in a pond in the plant site area. We feel this is an achievable goal since there is only the Bird's Nest aquifer to contend with in the shaft area and it should produce a very low volume of water. Pump tests recently conducted at the proposed shaft sites confirm the volume of water to be encountered.

(18) Question: 3.5.5, p. 3-63 - What is the quality of mine water? Does lessee have any plans to treat-use-reinject such excess mine water? Will construction of holding pond (3.19.2) be completed prior to shaft snking encountering the Bird's Nest Aquifer?

Answer: Core drilling does not indicate any water in the mining interval or adjacent to it, and therefore, we do not anticipate any mine water as such. However, the shafts may make a small quantity of water which in fact would be Bird's Nest water and of Bird's Nest water quality. If an excess quantity of mine water is encountered and this volume is beyond the capacity of the pond, a re-injection system would be established. Water in the waste water holding pond will be treated as necessary, and used in various portions of the process. A surface holding pond will be completed prior to encountering the Bird's Nest aquifer during shaft sinking.

(19) Question: 3.6.2.3, p. 3-70 - What measures will lessee take to protect raw shale piles from leaching and spontaneous combustion? What will be the nature of the impervious layer (P. 4-91)?

Answer: The raw shale stock pile will be open and exposed to rain and snow. However, this will be a fairly active pile which will both receive and discharge ore during most of the time the retorts are operating. Therefore leaching of the pile should be minimal. Also, a waste water retention dam and pond will collect all runoff from the site area. Since the stockpile is active, it is not anticipated there will be significant heating or spontaneous combustion problems. However, this pile will be visually inspected on a regular basis to determine its status. Compacted fill will form the base of the stockpile area.

(20) Question: Several questions as to water rights have arisen. Lessee needs to submit their plans for water supply?

Answer: The securing of a water supply for the development of Ua and Ub is of course very important. The description of the planned water supply facilities is found in our Detailed Development Plan Section 3.14 starting on page 3-144. Our current plan for Phase I is to develop a well collection system and an intake pumping station located in the alluvium on the south bank of the White River. A 1.7 mile 10 inch diameter pipeline from the intake would service the processing facility using a storage tank at the terminal end of the pipeline. Approximately 2700 acre feet per year will be required. The preferred water supply for Phases II and III is the proposed White River Dam and Reservoir. This facility is being designed by the State of Utah through the Utah Water Resources Board under the direction of the Division of Water Resources. Phase III water requirements are estimated at 22,600 acre feet per year.

The State of Utah provided White River with a letter of intent to provide the needed water. This letter is dated October 17, 1980 and is provided as Attachment No. 3. The important parts of the letter are shown below.

"It remains the intent of the Board of Water Resources to retain ownership of the White River Dam Project and water rights and to make the water developed by the White River Dam Project available to energy development on a contract basis. It further is the intent of the Board that if necessary, it will attempt to construct temporary water facilities to allow for the use of State water on an interim basis. Such water might be used to suppply the needs of energy companies prior to the completion of the White River Dam Project. In the event that the State does not receive the necessary permits and right of way easements to build the proposed White River Dam Project or even provide interim facilities, the Board would consider making water from its water rights available to energy companies on an individual company by company basis."

"Although no agreement can be finalized until the necessary permits and right-of-way easements are obtained, and while the State cannot guarantee that it can make the necessary amounts of water available, this letter of intent is to demonstrate a firm commitment from the State of Utah through the Board of Water Resources to provide water from the White River for energy development Specifically, the White River Shale Company, through previous letters and discussions has established a firm interest in obtaining water from the White River Dam Project. The Board has assured White River Shale Project it would supply water to its project when the dam is completed. This letter of intent is to further assure that the 27,100 acre feet needed by the White River Shale Project can be delivered by the proposed project if constructed as planned and that White River Shale Project is identified as one of several companies who would receive an assured delivery of water from the project."

The use of the White River Dam and Reservoir, therefore, is the avenue of delivery of water that White River has been pursuing most agressively. Other options have been and are being pursued. Currently under negotiation is the purchase of water from the Deseret Generation and Transmission Company. This water would come from the Green River through a pipeline which DG&T is building to service their coal fired power generating plant in Uintah County. The White River would extend the pipeline to Ua

and Ub. It appears that approximately 4200 acre-feet per year could be made available in this fashion.

In addition, Sohio Shale Oil Company and the Cleveland Cliffs Iron Company jointly own an approved water right application to approximately 10,800 acre-feet per year from the White River. While no agreement for its use by White River currently exists, several discussions have been held with Sohio and Cleveland Cliffs concerning its possible use in the future.

Discussions are also continuing with the Ute Indian Tribe concerning an option to purchase water under the Ute Indian Tribe's water right. No agreement exists.

Additional alternate water supply facilities are described in Section 7.13 of our Detailed Development Plan (page 7-67). These include purchase of water from the Green River, Starvation Reservoir, Red Fleet Reservoir and implementation of the Watson Reservoir Plan, Hells Hole Canyon Reservoir Plan, supply from the Birds Nest aquifer, pumping from the Douglas Creek aquifer or other miscellaneous storage and delivery options.

(21) <u>Question</u>: 3.11.3, p. 3-126 - Did lessee consider the potential for degradable waste beneath/in the retorted shale pile to lead instability of the pile?

<u>Answer</u>: The stability of the processed shale pile will be an important concern in the final design plan for the pile. The contribution of degradable waste beneath or in the pile is not believed to be great for several reasons.

a) For those wastes which can be admixed with the processed shale, whether on the conveyors or separately at the disposal site, the concentration of degradable material in the pile (i.e., ratio of degradable waste to processed shale) should be very low.
b) For those wastes which cannot be admixed with the processed shale (e.g., construction materials, general rubbish, etc.) a separate landfill will be used. It could eventually lie beneath the processed shale pile if satisfactory compaction can be achieved.

Of course, the OSO will be consulted prior to implementing any plan to handle non processed shale project wastes.

(22) <u>Question</u>: 4.4.1, p. 4-71, para. 1; 4.5.1, p. 480 - Can OSO assume that lessee's use of words "contamination", "pollution", and "degradation" is that of McKee and Wolf?

Answer: The McKee and Wolf definitions for the three subject words were not used in the DDP. It is our intention to prevent or provide appropriate mitigation measures where "contamination" or "pollution" (using McKee) are projected to occur or are detected by our field monitoring program.

(23) Question: 4.4.1.2, p. 4-71 - What duration is the 100-year storm data on p. 4-88 (2 inches in 24 hours)?

Answer: Throughout the DDP (As stated on page 4-88) a 24-hour period is the duration of the 100-year (return frequency) storm used in designing water retention facilities for the project. The design rainfall of 2.4 inches in 24 hours was extrapolated for the project area from "NOAA Atlas No. 2, Precipitation Frequency Atlas of the Western U.S., "Miller et. al., National Weather Service,, U.S. Department of Commerce, 1973.

Also, at this time, the WRSP-collected precipitation data are being statistically reviewed to verify the NOAA extrapolation for the White River site. The results of this site specific review will be fed into the design for the various stormwater handling facilities.

(24) Question: 4.4.3.3, p. 4-77 - What amount of precipitation does lessee assume for tankage design?

Answer: As required by the oil shale lease, petroleum storage tank dikes shall be designed to retain at least 110 percent of the total storage volume of tanks in the relevant area and a volume sufficient for maximum trapped precipitation and runoff. The precipitation component of the containment volume will be based upon a 24 hour rainfall amount of 2.4 inches (the 100-year storm).

(25) Question: 4.5.2, p. 4-83 - What permeability range does the lessee consider to be "impervious"?

Answer: With respect to the design of catchment basins, a permeability of 1×10^{-6} cm/sec or less is considered to be impervious.

(26) Question: 4.5.3, p. 4-94 - What basis for considering subsidence to be uniform? Plant pillar, topography, boundaries will tend to cause non-uniform subsidence.

Answer: The mine is being designed for a minimum of surface subsidence and with approximately 1,000 feet of depth we do not anticipate seeing any reflection of barrier pillars etc. However, large unmined areas such as the plant pillar and the leased boundary pillars will tend to cause non-uniformity. The words in the DDP were "relatively uniform subsidence", not absolute.

(27) Question: 4.6.2.2, p. 4-104,5 - What is the source of data for the "24 inch no-migration" statement?

Answer: This statement is based upon general knowledge of soils principles and practices regarding the depth of influence of evaporative withdrawal. Evaporation rate is governed by moisture gradients existing within the soil. There are usually two phases defining this phenomena; the "constant" and "falling" rate stages. During the constant rate stage the soils' ability to conduct water upwards is at a maximum because flow paths are moist and upward movement of water (and salts) is relatively unaffected by drying. However, the constant rate stage will evolve into the falling rate stage. At this point, surface drying becomes progressively more limiting to upward water movement. This is primarily due to the drying of exposed films of moisture which are the primary mechanism facilitating upward flow. Dr. R. J. Hanks of Utah State University (1980) states, "water that gets deeper into the soil stands a better chance of being conserved. In fact, water that penetrates below 25 cm for non-swelling (non-cracking) soils has very little likelihood of being lost by evaporation." Where coarse textured surface materials such as processed oil shale are exposed to drying influences, the constant rate stage will be lesser and thus depths of water and salts, subject to significant upward movement, will decrease substantially (10-14 cm).

Further, the statement was intended to include those salts that were leached to a depth beyond 24 inches and not the proportion of salts that might remain in closer proximity to the surface and thus be influenced by upward capillary migration. Based on the data reported by Fransway (Reference 4-12), salts in coarse textured shale are readily leached. When heat lamps were applied to shale surfaces during a leaching period capillary rise and surface deposition of salt was minimal. Personal field observations indicate that salt accumulation at the surface only occurs when fresh, damp shale (not leached by weathering) is exposed to the sun.

Literature Cited:

Hanks, R.J. and G.L. Ashcroft. 1980 Applied Soil Physics. Advanced Series in Agricultural Sciences No. 8. Springer-Verlag. New York, New York 157 pp.

(28) Question: 4.6.2.5, p. 4-112 - What data supports statement that "D" soils are below 44 inches in depth?

Answer: The DDP draws this statement from the soil survey conducted by Utah State University Foundation soil scientists during the baseline study. A report of findings can be found in Section V of the First Year Environmental Baseline Report for WRSP. Table V-2 of the subject report indicates that the electrical conductivity of the "D" soils below 113 cm is 28 mmhos/cm. Further discussion can be found in the USU soil survey report.

(29) Questions: 4.13.3.1, p. 4-167, 8, 9 - Can OSO assume that these drawings and the test are the schematic or conceptual only?

Answer: Figures 4.13-1 through 4.13-3 are indeed conceptualized drawings for the planned on-site hazardous waste disposal facility. The facility will be located in an area with sufficient volume to contain expected commercial amounts of hazardous material, with suitable topographic features allowing for remoteness from active work area, security, and isolation from and containment of surface runoff, and satisfactory geologic substructure based upon geotechnical investigations. The final design of the disposal facility will be based upon the characteristics of the chosen site, characteristics of the wastes to be handled, and applicable federel and state regulations in effect at the time of design. Of course, OSO review and approval will be obtained prior to development of the site.

(30) Question: 7.10.5.3, p. 7-56 - Explain data and testing to examine the expected "fully impervious barrier" formed by the Uinta Foundation. OSO assumes "impervious" only applied when the permeability is in the range of 10^{-5} Darcey. Waiting for lysimeter tests to determine if a liner for the processed shale is needed indicates that the pile will be started without a liner. If a liner is proven necessary, what actions would be taken to prevent leaching of the pile already started?

Answer: Section 7.10.5.3 discusses possible alternate means of water management relative to the processed shale disposal area. It is the WRSP plan to design water retention ponds in Southam Canyon to be impervious. However, there are no plans to underlie the processed shale pile with an impervious liner. This plan was adopted for the following reasons.

(a) It is the opinion of hydrogeological consultants to WRSP that the Uinta Formation rock will be impervious to percolation and migration of leachates into groundwater formations. This belief is based upon the geophysical testing conducted during the Baseline program. Based

upon the results of slant-hole drilling the Final Environmental Baseline Report concluded, "the physical competency displayed by the core as it was removed from the core barrel was very good. In particular, inclined fractures are nearly absent and only a few, relatively short vertical fractures were observed". Further, the inclined holes indicated that high angle fractures or joints are rare in that section of rock contained in the lower Uinta and upper Green River Formations on Ua and Ub.

(b) Not only does the overlying rock appear to be very competent, but also within the Southam Canyon area, the Birds' Nest Aquifer is 400-500 feet beneath the ground surface.

(c) As the processed shale is deposited in Southam Canyon, it is believed that sufficient compaction of the unsaturated shale can be achieved to greatly reduce the percolation of water through the pile. Combining the expected compactibility of the pile with the effects of plant evapotranspiration should result in little, if any, leachate reaching the subsurface. Of course, this will receive further investigation as the design of the pile progresses and the results of compaction and lysimeter tests become available from the on-tract processed shale test plot.

(31) Question: There is a discrepancy between the 73% recovery rate in the confidential data report and the 63% overall recovery including the shaft/plant pillar in the 100% of resource.

Answer: The 73 percent recovery rate refers to resource recovery in the panel areas whereas 63 percent recovery is for the total lease area including the haulageways, plant pillar, and lease boundary pillar areas. This number is subject to some modification as the final underground design proceeds. It is the intent of White River to recover all of the resource possible and we would hope the recovery percentage would increase as our mining experience with mining the Ua/Ub resource increases.

(32) Question: Lessee will commit to a detailed Spill Prevention Control and Contingency Plan and will consider P.L. 96-510 in its preparation.

Answer: It is planned to develop detailed Spill Prevention Control and Countermeasure Plans (SPCC) for each phase of project development (i.e., construction and operation). The

SPCC plan for construction will be a generic document used to guide the various project contractors and subcontractors in developing and implementing SPCC plans for their specific area of responsibility. However, WRSP staff will have primary responsibility relative to reporting of specific incidents. The construction SPCC plan will be available for review during the first quarter of 1982.

The operations SPCC plan wil be a specific document to guide spill prevention and clean-up during plant operations. This document is scheduled for completion in late 1984 prior to initial start-up of surface processing facilities.

P.L. 96-510 pertains to the control and containment of hazardous material spills. Where applicable WRSP will develop a plan to address this issue. However, during construction, compliance with this law and subsequent regulation will fall primarily with project subcontractors. They will be advised of the requirements of the act and will be required to comply with its mandates.

(33) Question: Ground water flow will be towards the White River along the structural dip. What long-term water quality effects might be expected as a result of ground water flow through the mine to the river? Need discussion on reservoir seepage to mine and mining effects on the integrity of reservoir.

Answer: White River does not anticipate any problem in mining the sub-surface resource because of the proposed White River reservoir. The enclosed letter (Attachment No. 4) from White River to The Utah Department of Natural Resources may help clarify our position on this subject.

(34) Question: What is the Vernal-to-tract and Craig-to-tract highway mileage, load class, and safe traffic density?

Answer: When the tract access roads from Bonanza to the proposed plant site are completed, the distance from Vernal to the tracts would be 53 miles (based upon existing U.S. 40 and Utah 45 access) or 42 miles (based upon the new Vernal to Bonanza highway route). The Craig to tract highway mileage (based upon U.S. 40 and Utah 45 access) would be 125 miles. The load class of these roads is AASHO H-20. Information concerning capacity of highways in the vicinity of WRSP can be obtained from the "Uintah Basin Transportation Study - Final Report" December, 1980 prepared by Van Wagner and Associates.

(35) Question: What is WRSP's commitment to mass transit from potential bedroom communities and from on-tract housing?

Answer: There is no present commitment to mass transit. However, WRSP recognizes the obvious desirability of mass transit during both the construction and operating phases of the project, and will promote and support the establishment and utilization of such a system.

(36) Question: What is the unused pumping capacity in existing common carrier pipelines that WRSP might seek to transport early production?

Answer: As yet, a detailed pipeline survey has not been made. Prior to such a survey, it will be necessary to:

1) Select a destination for the oil, and

2) Determine the pumping characteristics of the upgraded shale oil.

This in turn will depend on the specific upgrading process which is yet to be selected.

(37) Question: How many tank truck loads will be made in Phase I and over what roads?

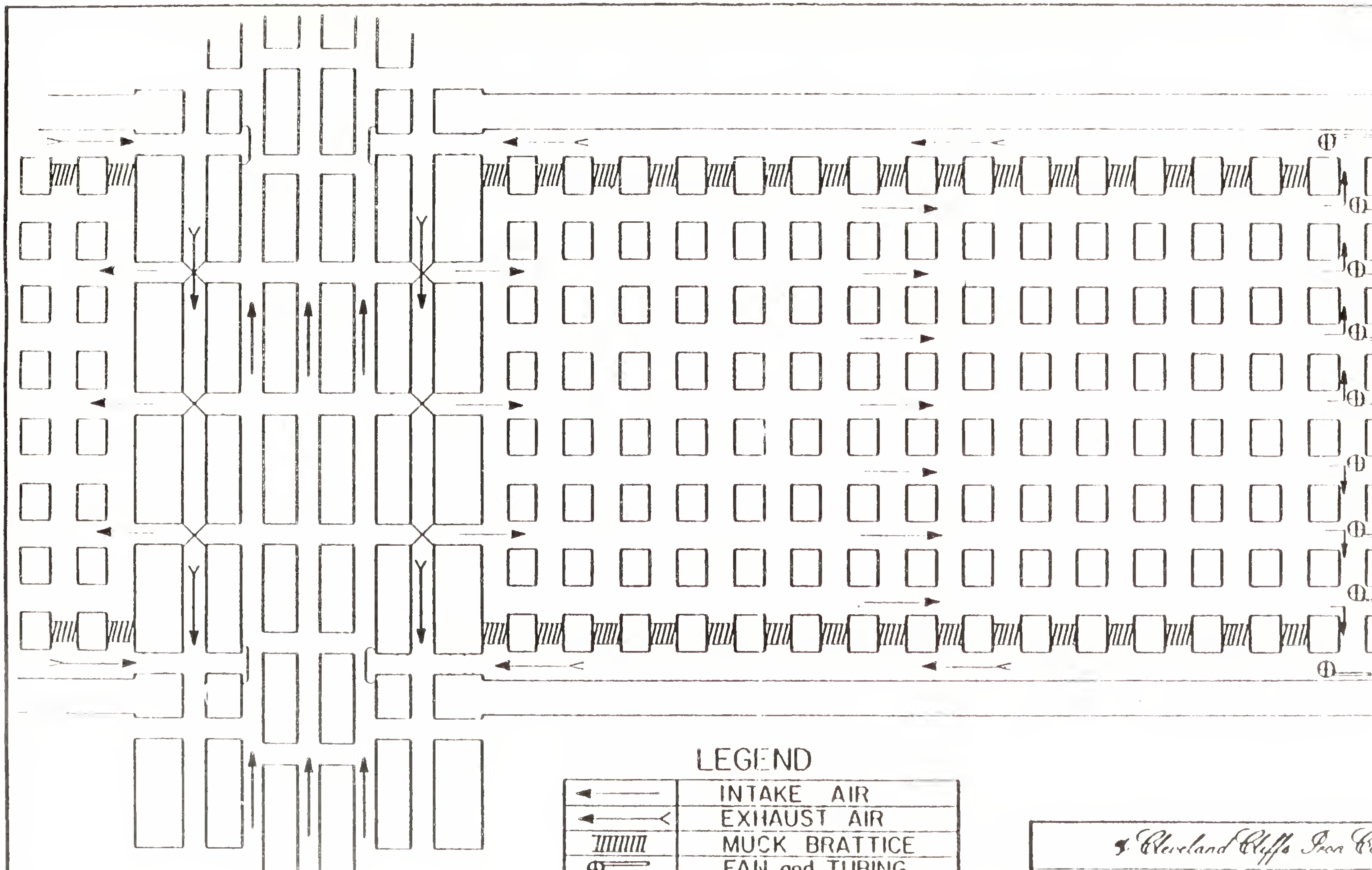
Answer: The DDP plan is to pipeline the finished product. See Page 3-20.

ATTACHMENT NO. 1

FEDERAL NEW SOURCE PERFORMANCE STANDARDS

Type of Emission	Emission Limits: Fossil-Fuel Fired Boilers	Emission Limits: Refineries	Emission Limits: Petroleum Storage Vessels
Particulate Matter	0.10 lb/MMBtu; 20% opacity except for one 6-minute period per hour of not more than 27% opacity	1.0 lb/1,000 lb of coke burn-off in the catalyst regenerator except 0.1 lb/MMBtu from use of fossil fuel; 30% opacity except for one 6-minute average in any 1 hour	N/A
Sulfur Dioxide	(a) <u>Liquid Fuel</u> 0.80 lb/MMBtu (b) <u>Solid Fuel</u> 1.2 lb/MMBtu	0.1 gr/dscf H_2S in fuel gas or equivalent treatment of exhaust gas. For Claus sulfur plants, 0.025% by volume of SO_2 at 0% O_2 on a dry basis if control by oxidation or reduction and incineration; if reduction not followed by incineration, 0.03% S and 0.001% H_2S as SO_2	
Nitrogen Oxides	(a) <u>Gaseous Fuel</u> 0.20 lb/MMBtu expressed as NO_2 (b) <u>Liquid Fuel</u> 0.30 lb/MMBtu expressed as NO_2 (c) <u>Solid Fuel (except lignite)</u> 0.70 lb/MMBtu expressed as NO_2	N/A	N/A
Carbon Monoxide	N/A	0.050% by volume from cat cracking unit	N/A
Volatile Organic Compounds	N/A	N/A	(a) If the true vapor pressure of the petroleum liquid, as stored, is equal to or greater than 78 mm Hg (1.5 psia) but not greater than 570 mm Hg (11.1 psia), the storage vessel must be equipped with a floating roof and double-seal closure device, a fixed roof with an internal floating type cover and closure device, a vapor recovery system and a vapor return or disposal system which is designed to reduce volatile organic compounds emissions by at least 95 percent by weight, or an equivalent system. (b) If the true vapor pressure of the petroleum liquid, as stored, is greater than 570 mm Hg (11.1 psia), the storage vessel must be equipped with a vapor recovery system and a vapor return or disposal system which is designed to reduce volatile organic compounds by at least 95 percent by weight. (c) There are no controls associated with storage vessels for petroleum liquids with true vapor pressures under 78mm Hg (1.5 psia).
Subject Facilities	Phase I, II and III boilers	Phase I, II and III sulfur recovery facilities (i.e., Claus and SCOT units).	Phase I, II and III petroleum storage tanks greater than 40,000 gallons.

ATTACHMENT NO. 2



LEGEND

◄———	INTAKE AIR
◄———<	EXHAUST AIR
///////	MUCK BRATTICE
Φ═	FAN and TUBING
‡	AIR DOOR
⊂⊃	AIR CURTAIN
—S—	STOPPING
X	OVERCAST

The Cleveland Cliffs Iron Company

WESTERN DIVISION — RIFLE, COLORADO 81650

TYPICAL MINE PANEL VENTILATION PLAN	SCALE 1"=200'	DRAWN BY P.A. TARVER
DATE 02/18/81	APPROVED BY	DRAWING NUMBER 8102-UM-VI

Dept. of Natural Resources

ATTACHMENT NO. 3

DIVISION OF WATER RESOURCES

Suite 300
231 East 400 South
SALT LAKE CITY, UTAH 84111
Tel: (801) 533-5401

Daniel F. Lawrence
Director

October 17, 1980

Mr. Rees Madsen
White River Shale Project
c/o Senior & Senior
P.O. Box 11808
Salt Lake City, UT 84147

Dear Mr. Madsen:

As has been discussed in recent meetings between your project representatives and the Division of Water Resources, I am sending this letter to reaffirm the intent of our Board to build the White River Dam Project and to supply water from it to your project.

The State of Utah, acting through the Utah Board of Water Resources, has had an interest in the construction of a dam on the White River for many years. On May 10, 1965 the Board filed an application with the State Engineer for 350 cubic feet per second (cfs) and 250,000 acre-feet from the White River. On March 5, 1976 the Board filed an application to segregate 105,000 acre-feet of the parent application for use by the White River Dam Project. The application to segregate included an application for a 2,500 cfs nonconsumptive use right for hydroelectric generating. During the period from 1965 to 1975 the Division of Water Resources initiated field investigations to determine a suitable site for a dam on the White River. After these field investigations, the proposed site in Section 17, T10S, R24E, six miles southwest of Bonanza, was selected as the most suitable dam location.

After the selection of the site, the Division prepared a "Proposed Action Plan" for the White River Dam. This Proposed Action Plan was presented to the Bureau of Land Management (BLM) with an application for a right-of-way easement and a request for BLM to begin the preparation of the Environmental Impact Statement (EIS) so that a right-of-way easement could be approved.

The August 1975 right-of-way application was accepted but the request for BLM to begin the EIS was not acted on by BLM. The Division of Water Resources, with continual assistance from the Governor, sought to have BLM begin the EIS work from 1975 until August 1979, when BLM finally gave its approval to begin the preparation of the EIS. A BLM contract to a consultant (BIO/WEST, Logan) to write the draft EIS was finalized in May 1980. From the schedule given for the EIS, the document should have been completed by February 1981 with a decision on the right-of-way easement by March of 1981. Due to the position taken by the U.S. Fish and Wildlife Service that the project may jeopardize the continued existence of three endangered species (Colorado squawfish, humpback chub and bonytail chub) the schedule for completion of the EIS has been changed. It is now scheduled that a draft EIS will be available by the end of November 1980. The draft EIS will be minus the Biological Opinion of the Fish and Wildlife Service. The draft EIS will go through the public review process and will then be held pending the resolution of the endangered species issue. When problems with the endangered species are resolved, a final EIS will be released.

With the approval for the preparation of the EIS, the Division of Water Resources engaged Bingham Engineering to prepare the White River Dam Project final design, plans and specifications. These plans are to be submitted to our office for review by April 1, 1981. It is felt that if the BLM right-of-way easement could have been approved in March of 1981, the other necessary permits and approvals could have been obtained over the next few months so that construction of the project could have started in August of 1981. The position taken by the U.S. Fish and Wildlife Service has now presented the State with uncertainties on the timing and the likelihood of the Division building the White River Dam as proposed.

As demonstrated in the October 2, 1980 meeting between Governor Matheson and the Utah Board of Water Resources, it remains the intent of the State of Utah to resolve our problem with the U.S. Fish and Wildlife Service and to proceed with construction of the White River Dam at the earliest possible date. It remains the intent of the Board of Water Resources to retain ownership of the White River Dam Project and water rights and to make the water developed by the White River Dam Project available to energy development on a contract basis. It further is the intent of the Board that if necessary it will attempt to construct temporary water facilities to allow for the use of State water on an interim basis. Such water might be used to supply the needs of energy companies prior to the completion of the White River Dam Project. In the event that the State does not receive the necessary permits and right-of-way easements to build the proposed White River Dam Project or even provide interim facilities, the Board would consider making water from its water rights available to energy companies on an individual company-by-company basis.

Although no agreement can be finalized until the necessary permits and right-of-way easements are obtained, and while the State cannot guarantee that it can make the necessary amounts of water available, this letter of intent is to demonstrate a firm commitment from the State of Utah through the Board of Water Resources to provide water from the White River for energy development. Specifically, the White River Shale Company, through previous letters and discussions, has established a firm interest in obtaining water from the White River Dam Project. The Board has assured White River Shale Project it would

supply water to its project when the dam is completed. This letter of intent is to further assure that the 27,100 acre-feet needed by the White River Shale Project can be delivered by the proposed project if constructed as planned and that White River Shale Project is identified as one of several companies who would receive an assured delivery of water from the project.

The Board wishes to assure the White River Shale Project that it intends to sell the water at a price that represents a reasonable return to the project. This price will be based on the total construction cost of the dam and reservoir, the quantity of water to be sold from the project, the schedule of water needed by the various companies, the O&M cost for the project, and a reasonable interest rate.

We view this Letter of Intent to be an essential beginning step in the process of continued discussions and negotiations necessary to reach a firm contract for water delivered from the White River Dam to White River Shale Project.

Sincerely,

Daniel F. Lawrence

Daniel F. Lawrence
Director

cc: Governor Scott Matheson
Gordon E. Harmston
Philip S. Knight
Bill M. Gibson
Laurence Y. Siddoway

ATTACHMENT NO. 4

WHITE RIVER SHALE PROJECT

100 WEST WALNUT STREET
PASADENA, CALIFORNIA 91124
(213) 440-6580
Telex: WH: 675-336

September 15, 1981

Mr. Daniel F. Lawrence
Utah Dept. of Natural Resources
Division of Water Resources
231 East 400 South, Suite 300
Salt Lake City, Utah 84111

Dear Mr. Lawrence:

Thank you for sending us a copy of the White River Dam geotechnical report for review and comment. I have read the report with a great deal of interest and want to compliment you and Bingham Engineering on a thorough and well-documented study. As you know, I have been closely associated with the geologic, hydrologic, and mining aspects of the White River Shale Project since mid 1975, and over this period we have investigated many of the same concerns as were covered in this study. The results of our work have led us to the same general conclusions as reported by Bingham Engineers, that the installation of the proposed White River Dam and reservoir will have negligible effect on the proposed oil shale mining activities of the WRSP on Tracts Ua and Ub.

To further expand on this comment, following are some specific points as they relate to this subject.

- WRSP is planning to mine using a room and pillar method with dimensions such that surface subsidence will be negligible. This is based on a great deal of rock mechanics work on core samples by the Bureau of Mines.

- WRSP drilled two angle core tests through the mining interval to determine joint conditions in the underground. Both tests concluded that joint frequency decreased with depth and joints were tight. No evidence of fluid percolation along existing joints was detected.

- The 400 feet of shales and marlstones existing between the mining interval and the overlying Birds Nest aquifer, will prevent any possible increase of hydraulic head in the Birds Nest due to the reservoir to be seen in the mine.

- White River plans to begin mining operations about one mile southeast of the proposed reservoir south shore line and to mine in an easterly direction for the next several years. This has always been our plan and would not change with or without the reservoir. We do not plan to be in the vicinity of the reservoir for some 8 to 10 years, and this will certainly give us time to evaluate any change in conditions not presently

understood. We do not anticipate any reduction of presently calculated recoverable ore reserves due to the proposed White River Dam Project.

Again, I would like to reiterate that in my opinion based on experience and evaluation of the data collected that the White River Dam and its resultant reservoir will not have a significant adverse impact on the safety, ore recovery, or operation of the White River Shale Project mining plans for Tracts Ua and Ub. We feel we are aware of these impacts, have evaluated them, and we have plenty of time to incorporate new data as it becomes available from actual mining operations.

Very truly yours,

Lowell Page

Lowell B. Page

LBP:pm

cc: R. N. Pratt
C. E. Doney
J. W. Godlove
WRSP Pasadena File

WHITE RIVER SHALE OIL CORPORATION

SUITE 500 PRUDENTIAL BUILDING, 115 SOUTH MAIN STREET
SALT LAKE CITY, UTAH 84111
(801) 363-1170

December 21, 1981

Mr. Brent C. Bradford
Bureau of Air Quality
Divison of Environmental Health
P.O. Box 2500
Salt Lake City, Utah 84110

Dear Mr. Bradford,

Your letter of November 18, 1981 requested additional information relative to the Prevention of Significant Deterioration permit application submitted for the White River Shale Project. Following are our responses to each question raised in your letter.

1. Neither the Union retort or the Superior retort will produce a particulate laden steam cloud as a result of processed shale cooling. Thus, in our opinion the particulate emission rates from these facilities should not be changed.

   The Union B retort included a cooler to condense the steam. Any particulate matter entrained in the steam would be collected in the condensed liquid and would not be discharged to the atmosphere. Although Union is currently revising the design of its processed shale cooling system, there will continue to be no particulate discharge from the retort.

   The Superior retort water seal is also mechanically enclosed. Any dust raised internally in the retort simply joins the process gas stream and is treated before combustion.

   Details of the mechanical design for both retorts are not available at this time. This information should be available in six to nine months.

2. At this time information regarding trace element discharges from an oil shale processing facility is limited at best. There are three factors which contribute to the problem of quantifying and evaluating the environmental effects of trace elements, in particular mercury and beryllium. These are;

a) The amount of information concerning the distribution of these materials in the various products of oil shale processing is limited.
b) The methods of sampling and analyzing for the trace elements have not been well established.
c) The "de minimus levels" established by the EPA for the controlled elements are so low that detection is virtually impossible. Thus, certification of compliance is difficult except by qualitative means.

The following discussion presents our interpretation of available information concerning the emission of mercury and beryllium from WRSP. Our emission calculations for Phase III operations are included in Attachment No. 1.

Mercury

Based upon analysis of raw shale from the mining zone of Ua and Ub, mercury levels in the raw shale vary from 0.06 - 0.12 ppmw with an average of 0.10 ppmw.

As the calculations show, it is not expected that the project's emission of mercury (0.0048 tons/year) will exceed the current EPA de minimus level for the compound (0.1 tons/year). This is due to a combination of particulate emission controls for raw and processed shale sources (as shown in the emission inventory tables in Section 5 of the PSD application) and the raw shale upgrading facilities. The guard bed reactors and the hydrotreating units are especially important in removing mercury (and other trace metals) from the shale oil. This results in substantial control (99.9 + percent) of mercury emissions from the combustion of upgraded shale oil in various fired units.

Since the calculated emissions of mercury do not exceed de minimus levels, no further evaluation of this pollutant is required.

Beryllium

Available information concerning the presence and distribution of beryllium in oil shale processing facilities is very limited. Although the results of our re-evaluation of beryllium emissions suggests that they may exceed the established de minimus level, we believe this is more a function of the unreasonably low de minimus concentration and the lack of adequate data rather than a phenomena unique to the WRSP.

Because beryllium concentrations in Ua/Ub oil shale have not been measured, it was assumed that the average concentration of the metal in raw oil shale is 1.5 ppm, based upon available literature. At this level, the various sources of raw shale dust will be the major sources of beryllium emission (about 66 percent of the total). These sources are identified on page B-3 of the PSD application and the proposed BACT control measures are discussed in Section 5 of the application. It is our opinion that BACT for raw shale particulates in general is BACT for beryllium.

It appears from available data that virtually all of the beryllium in raw shale will remain on the processed shale. By our calculations about 25 percent of the beryllium emissions will be emitted from the processed shale handling and disposal systems. As with the raw shale emission sources, BACT for beryllium is equivalent to BACT for the particulate sources from processed shale handling.

Only 6 percent of the beryllium emission is due to shale oil combustion. As with mercury BACT is provided by burning upgraded shale oil product as supplemental fuel in various fired units.

The beryllium emission from diesel-fueled mobile equipment will amount to only 3 percent of the total. Proper maintenance of the units in compliance with MSHA requirements will be BACT for these sources.

Although, by calculation, WRSP may emit beryllium in greater than de minimus levels, no identifiable adverse effect is anticipated. First, the level of emission (0.0014 tons/year) is only 35 percent of the standard established under the National Emission Standards for Hazardous Air Pollutants (NESHAPS), which itself protects the public health with an adequate margin of safety. Second, the projected ambient air concentration of beryllium would be less than 10 percent of the de minimus level established in the PSD regulations (i.e., 0.00003 ug/m^3 versus the standard of 0.0005 ug/m^3). This is derived by proportioning the beryllium component of the total particulate emission against the modeled particulate increment consumption for Phase III (i.e., 36.8 ug/m^3 for the 24 hour average).

Thus, it is our opinion that beryllium emissions are being properly controlled by the project and that the environmental impacts associated with beryllium releases (if any) will be very slight.

3. In those instances where additional nitrogen oxide control, beyond fuel gas treating and the combustion of upgraded shale oil, was required to comply with best available control technology (BACT) requirements for various fired units, low-NOx burners were added. While the specific manufacturer of the burners has not been selected at this time, they will certainly involve a staged combustion concept typical of low-NOx burners. Also, through the use of oxygen and combustibles analyzers, an efficient low excess air operation will be maintained to reduce NOx emission levels.

   As shown on the emission inventory tables (Tables 5-1 through 5-3), low-NOx burners wil be used only on those units firing a combination of by-product offgas and upgraded shale oil. The one exception, as you point out, is on the hydrotreater reactor feed furnaces. These furnaces will burn only treated high-BTU offgas. As discussed on pages 5-84 and 5-90 of the application, it is our opinion that the 99.9 percent removal of ammonia through gas treating represented BACT for the high-BTU gas used in the subject sources.

   The resultant emission of NOx for the hydrotreater furnaces without low-NOx burners is essentially equivalent to the NOx emissions of the oil/gas fired furnaces with low NOx burners.

4. The boiler plants for the project will use treated low-BTU byproduct offgases (from the Superior retorts) and supplemental upgraded shale oil as fuel to provide steam and power (Phases II and III only) to the oil shale processing plant. The flue gas from these boilers will have a very low concentration of sulfur dioxide, being on the order of 85 ppmv. This is judged by the project to represent BACT for this source.

   However, to comply with the currently applicable SD Class II increments for SO_2 during the commercial phases of the project, the boilers will be equipped with flue gas desulfurization units designed to remove an additional 80 percent of the SO_2 from the boiler flue gases. (It is planned that the Phase I steam plant will be retrofitted with FGD during Phase II. The Phase II and III steam plants will be constructed including FGD systems).

For the PSD application it was premised that the FGD system will be of a non-regenerable lime/limestone design. The actual FGD system will not be selected and designed until the project enters the commercial phase. However, the overall efficiency (i.e., the final SO_2 emission rate) will be consistent with the current application.

The anticipated FGD system characteristics are presented in Attachment No. 2 for the lime/limestone system.

Of course, there would be the alternative of installing a regenerable FGD system (i.e., ammonia scrubbing). However, it would be expected that the total air emissions would be no greater than for the non-regenerable system. This alternative will receive further investigation prior to a decision as to the type of FGD to be installed.

5. It is planned to construct a single TOSCO II fines-type retort in each of the two commercial phases. The expected release of hydrocarbons from the lift pipe area of the TOSCO process is discussed on page 5-98 of our PSD application. Our estimate of hydrocarbon emissions from this source is based upon the TOSCO retort entitled "Lift Pipe Hydrocarbon Emissions" prepared in February, 1978 and is still considered applicable to TOSCO II emission estimates.

According to the TOSCO report, which is included as Attachment No. 3 to this letter, tests at their semiworks plant have indicated that most of the hydrocarbon evolution occurs in the third (and hottest) lift pipe. As discussed in our application, hydrocarbon emissions from the third lift pipe are controlled by a thermal incinerator. As the raw shale is preheated in the first two lift pipes (using cooled flue gases from the incinerator), less than 100 ppm of hydrocarbon will be liberated according to the TOSCO tests. This resulted in a 75 ppmw level of hydrocarbons in the total exhaust to the venturi scrubber, which represented 85 percent overall hydrocarbon efficiency.

The WRSP application took no credit for the collection of condensible hydrocarbons in the wet venturi scrubbers. However, the TOSCO report suggests that the hydrocarbons in the exhaust stream may be 50 percent condensible at exhaust conditions.

It is our belief that this control scheme represents BACT. Further information relative to this source should be available following start-up of the Colony Project in Colorado which is well in advance of WRSP's construction of its first TOSCO retort.

6. Page 5-57 of the PSD application discusses White Rivers' estimate of gaseous emissions from mobile sources within the mine. It is our belief that the use of mobile equipment designed to comply with applicable safety regulations and our commitment to properly maintain this equipment represented BACT for these sources.

In calculating emissions from underground mobile equipment, the EPA exhaust estimates for heavy diesel powered vehicles as contained in EPA's AP-42 publication were compared with MSHA exhaust requirements for mobile diesel-powered transportation for gassy non-coal mines and tunnels (30 CFR Part 36). The allowable exhaust emissions under MSHA rules are the same as the EPA exhaust estimates. Also, the Utah State Industrial Commission (USIC) requirements are basically the same as the MSHA requirements. Thus, exhaust emissions presented in the PSD application, which were based on EPA's AP-42 publication, are in compliance with MSHA and USIC exhaust requirements.

As an alternative to the use of diesel equipment, the use of electrical mobile production units for underground mining has been investigated. This alternative is not considered feasible because electrical units of the necessary size exceed the state of the art. Such existing units are too small for our needs. For example, the largest electrical powered LHD (load-haul-dump) presently manufactured has a capacity of 5-8 cubic yards. The project requires 8-13 cubic yard LHD's which may not be available in electrical models in a timely manner. Also, the mobility of electrical units is restricted and there is a continuing concern for safety involving the tailing cables.

Thus it is our opinion that the use and proper maintenance of MSHA approved diesel vehicles is BACT for underground mining operations.

7. Page 4-40 of the PSD application states that sour water degassed vapors would be vented to the flare in minute amounts. "Minute amounts" actually re-

fers to the amount of hydrogen sulfide in the vapors from the degasser through which the sour water will pass prior to entering the storage tank. Vapors from the degasser will contain hydrocarbons, sulfur compounds, and ammonia. The degasser vapors will be treated in a caustic scrubber to remove all of the sulfur and ammonia. The unrecovered hydrocarbons produced at a rate of approximately 10 pounds per hour, will then be sent to the flare for combustion.

It is our understanding that this should complete the technical review of our air quality permit application. We look forward to the Bureau's completeness decision for the application.

Sincerely,

JAMES W. GODLOVE
Director of Environmental Affairs

JWG:mrw

Enclosures

cc: P. Rutledge - Oil Shale Office
D. Kircher - USEPA - Region VIII

ATTACHMENT NO. 1

EMISSION CALCULATIONS FOR NON-CRITERIA POLLUTANTS

MERCURY AND BERYLLIUM

PHASE III LEVELS

MERCURY (Hg)

De minimus level = 0.1 ton/yr
Level in raw oil shale = 0.1 ppm (1)

Hg in raw oil shale:
(176,740 t/d) (328.5 d/yr) (0.1 ppm) = 5.8 t/yr

Hg in raw shale dust:
(613 t/d) (0.1 ppm) = 6.1×10^{-5} t/yr (2)

Hg in processed shale:
Assume 20% is retained on the processed shale (3)
(5.8 t/yr) (0.20) = 1.16 t/yr

Hg in processed shale dust:
$\frac{(232\ t/yr)}{(176,740\ t/d)\ (328.5\ d/yr)}$ (1.16 t/yr) = 4.6×10^{-6} t/yr (2)

Hg in product gas:
0.33% of Hg in raw shale occurs in raw product gas. (3)
(5.8 t/yr) (0.0033) = 0.019 t/yr
However, through gas treating, this particulate component should be removed. Thus, contribution from this source is nil.

Hg in retort water:
0.6% of Hg in raw shale occurs in retort water. (3)
(5.8 t/yr) (0.006) = 0.035 t/yr

Hg in raw shale oil:
The remainder of Hg should be contained in the raw shale oil. This amounts to (5.8 t/yr) - (1.16 t/yr + 0.035 t/yr) = 4.6 t/yr. This agrees in general with Reference (3) which cites 70 + percent Hg enrichment in shale oil.

Hg in upgraded shale oil:
The upgrading process will use a guard bed reactor and a hydrotreating unit. Both serve to demetalize the raw shale oil product. The efficiency of demetalization will exceed 99.9 percent (4).
(4.6 t/yr) (0.001) = 0.0046 t/yr

Hg from diesel fuel combustion-
E.F. = 0.3 lb/10^{12} BTU (5)
Q=(30,000 gal/d) (7.1 lb/gal) (19,340 BTU/lb)
(328.5 d/yr) (0.3 lb/10^{12} BTU) (t/2000 lb)
=2.1×10^{-4} t/yr

Total Hg emission from Phase III operation:

Raw shale dust	6.1×10^{-5} t/yr
Processed shale dust	4.6×10^{-6} t/yr
Product offgas fuel	nil
Upgraded shale oil fuel	4.6×10^{-3} t/yr
Diesel fuel	2.1×10^{-4} t/yr
Total	0.0048 t/yr

BERYLLIUM (Be)

Deminimus level = 00.0004 t/yr
Level in raw oil shale = 1.5 ppm

Be in raw oil shale:
(176,740 t/d) (328.5 d/yr) (1.5 ppm) = 87 t/yr

Be in raw shale dust:
(613 t/yr) (1.5 ppm) = 87 t/yr

Be in processed shale dust= d
According to Reference (3) it appears that Be will reside mainly in retorted shales and is not enriche in shale oils, retort gases, or retort waters.

$$\frac{(232\ t/yr)}{(176{,}740\ t/d)\ (328.5\ d/yr)}\ (87\ t/yr) = .00035\ t/yr$$

Be in product offgas: t
There is no published information concerning the ed amount of Be which may reside in product offgas, bu following gas treatment particulate should be remov prior to combustion.

Be in raw shale oil: n
Be in raw shale oil is below detectible levels. If according to Reference (3), 0.1 percent of the Be i raw shale appears in the raw shale oil then,
(87 t/yr) (0.001) = 0.087 t/yr

oil

Be in upgraded shale oil:
Following hydrotreating the Be levels in raw shale will be reduced by 9.9+ percent.
(0.0087 t/yr) (0.001) = 0.000087 t/yr)

Be in diesel fuel combustion:
E.F. = 0.07 lb/10 Btu
Q = (30,000 gal/d) (7.2 lb/gal) (19,340 Btu/lb) (328.5 d/yr) (0.07 lb/10 Btu) (t/2000 lb)
= 4.8 x 10

Total Be from Phase III operations:

Raw Shale Dust	0.00092 t/yr
Processed Shale Dust	0.00035 t/yr
Product offgas fuel	nil
Upgraded shale oil fuel	0.000087 t/yr
Diesel fuel	0.000048 t/yr
	0.0014 t/yr

References:

(1) Results from raw shale analysis from Ua/Ub mine zone.

(2) See page B-3 of PSD application

(3) Trace Elements Associated with Oil Shale and Its Processing, USEPA Region VIII, EPA-908/4-78-003 (1977).

(4) Personal communication between B. Bush (Phillips) and Chevron Oil Company.

(5) Health Impacts, Emissions and Emission Factors fo for Non-criteria Pollutants Subject to Deminimus Guidelines andd Emitted from Staionary Conventional Combustion Processes, USEPA, EPA-450/2-80-074 (1980).

ATTACHMENT NO. 2

FGD SYSTEMS	LIMESTONE	
PHASE	II only (a)	III only (b)
Inlet Flue Gas		
SCFM @ 60°, 1 atm	332,300	652,000
Temp; °F	350	350
Press: psia	12.2	12.2
SO_2 conc; ppm	85	85
SO_2; lbs/hr	281	551
Humidity; lbs H_2O/lb dry gas	0.15	0.15
Wet Bulb Temp; °F	144	144
Reagent; lbs/hr	410	800
Reagent purity; %	95	95
Process Water; GPM	167	335
Air for Oxidation; scfm	105	212
Electric Power		
ID Fan; HP	2 @ 600 ea	4 @ 600 ea
Pumps; HP	1470	2960
Auxilliary; HP	120	200
Total Electricity; KW	2400	4500
Flue Gas Reheat		
Gas temp in; °F	144	144
Gas temp out; °F	350	350
Sat. Steam; lbs/hr	88,000	172,000
Steam Temp; °F	256	256
Steam Press; psia	33	33
Gas to Stack		
SCFM @ 60° F; 1 atm	361,000	708,300
Temp; °F	350	350
SO_2 conc; ppm	16	16
SO_2; lbs/hr	56	110
Waste Stream		
Flow Rate; lbs/hr	815.2	1644
Composition; wt %	calcium sulfite 80 calcium sulfate 20 water	

a) The Phase II values assume retrofit of the Phase I boilers and equipping Phase II boilers with FGD as built. Thus, both Phase I and Phase Phase II boilers values are shown.

b) The Phase III values are for Phase III boilers only.

ATTACHMENT NO. 3

TOSCO LABORATORY

DATA LETTER 74-114.

RE: LIFT PIPE HYDROCARBON EMISSIONS

LIFT PIPE HYDROCARBON EMISSIONS

The EPA has asked how hydrocarbon emissions from lift pipes were measured and/or estimated, and how the incinerators are to be operated. This memo serves to collect relevant information into one place, for inclusion in the PSD permit application. Some discussion of the history of various semi-works and pilot plant programs is necessary in order to provide perspective.

BACKGROUND

Semi-works testing of lift pipe emissions revealed high (400-700 ppm as carbon) concentrations of hydrocarbons, with little or no removal by the venturi scrubber. These levels were judged unacceptable because it appeared that Colorado opacity standards might not be met, and because the condensible fraction of the hydrocarbons must be included with particulates according to the applicable emission regulations, which were proving costly enough to meet for solids alone.

For these reasons, a program was conducted at Tosco's Rocky Flats pilot plant to develop and demonstrate methods for minimizing hydrocarbon emissions. It was subsequently shown that a thermal incinerator operating at approximately 1400° F. and 0.5 seconds residence time was highly efficient (approx. 99%) in removing hydrocarbons from a hot, dusty flue gas stream.

Tests at the semi-works plant had indicated that most hydrocarbon evolution occurred in the third (hottest) lift pipe, with less than 100 ppm evolving in the first two lift pipes. While exact duplication of the semi-works configuration and operating conditions was not possible at the pilot plant, results were consistant with this observation.

C. F. Braun & Co. has estimated that 75 ppmw of hydrocarbon will be contained in exhaust flue gas from the commercial lift pipes after incineration; this corresponds to about 50 lb/hr per stack. If the hydrocarbon is 50% condensible at exhaust conditions, as we believe based upon extrapolated vapor pressure curves and rather spotty semi-works data, the estimate to be used in the permit application should be 25 lb/hr.

SAMPLING PROCEDURE

Several hydrocarbon sampling techniques were attempted at the semi-works, including sample trains with condensers and filters for continuous collection. All of these techniques indicated lower concentrations than determined by pulling a free flowing stream of flue gas into an evacuated sample bomb. A continuous (Beckman) hydrocarbon analyzer used on the incinerator outlet during pilot plant tests also gave lower

values than corresponding laboratory analyses. For these reasons, the preferred procedure for hydrocarbon determinations was judged to be sampling with evacuated sample bombs, followed by heating of ~~the bombs~~ and analysis by gas chromatography in the laboratory. The same procedure would be recommended for monitoring of commercial plant emissions, with the following caveats and observations kept in mind:

(1) Sampling at very low concentrations, e.g. at incinerator or scrubber outlets, probably cannot be expected to be accurate to within 20-30%. At such low concentrations, results can be influenced by residual hydrocarbons in the sample bombs (even after washing), or by the vapor pressure of fingerprints, stopcock grease, rubber tubing, etc.

(2) For sampling dusty flue gas streams, an in-line stainless steel filter has proven useful in keeping dust out of the sample bombs.

(3) Minute-to-minute and hour-to-hour fluctuations in hydrocarbon content can occur as a result of variations in flow rates, fines content, etc. Replicate samples will practically always be desirable, and even then great care must be used in the determination of any "average" or "maximum" concentrations.

(4) In the sampling of hot flue gas streams with moderately high hydrocarbon content, condensation (and re-evaporation) of oil can occur in the sample bomb inlet.

For all of these reasons, it must be anticipated that any monitoring requirement imposed as a condition of a permit for the commercial plant will need to be flexible. Sampling and analytical requirements will be far from routine, so that adequate time must be allowed to develop procedures and to train personnel. In the interim, we would expect it to be adequate to provide only for reasonable reporting of progress to the monitoring agencies.

[illegible] [illegible] to [illegible] 2-10-78

Addendum #1
EPA PSD Application

TOSCO CORPORATION
10100 SANTA MONICA BOULEVARD
LOS ANGELES, CALIFORNIA 90067
213/552-7000
CABLE ADDRESS: TOSCOPETRO

February 10, 1978

Dr. Max Legatski
Atlantic Richfield Company
1500 Security Life Building
Denver, Colorado 80202

Dear Max:

As we discussed yesterday, the basis for 25 pounds per hour of condensable hydrocarbons in the preheat stack is as follows:

1) Hydrocarbon content of the first lift pipe flue gas - 75 parts per million (as carbon).

2) Mass rate of the first lift pipe flue gas - 572,832 pounds per hour.

3) Hydrocarbon content of the first lift pipe flue gas - 75 parts per million x 572,832 pounds per hour ÷ .85 pounds carbon per hydrocarbon = 50 pounds per hour.

4) Condensable hydrocarbon - .5 x 50 pounds per hour = 25 pounds per hour.

This derivation represented our best engineering judgement in 1973 and 1974.

Sincerely yours,

CHARLES S. WAITMAN

CSW:gh

Addendum #2
EPA PSD Application

TOSCO CORPORATION
10100 SANTA MONICA BOULEVARD
LOS ANGELES, CALIFORNIA 90067
213/552-7000
CABLE ADDRESS: TOSCOPETRO

February 10, 1978

Dr. Max Legatski
Alantic Richfield Company
1500 Security Life Building
Denver, Colorado 80202

Subject: Particulate Emission Estimates

Dear Max:

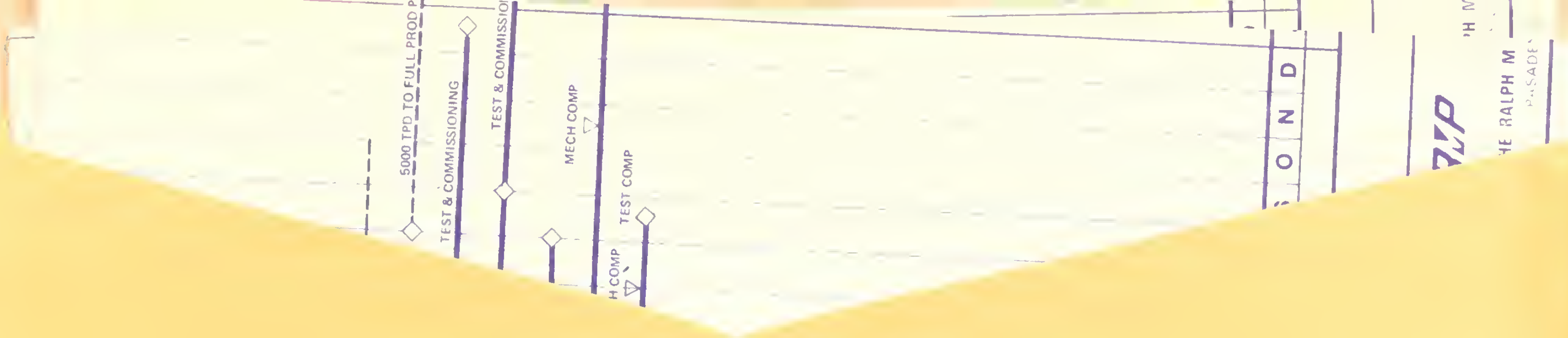
The attached Tables 1 and 2 represent all vendor data received by Colony and Foster Wheeler for the TOSCO II scrubbers. As we discussed your model will incorporate the estimates as listed below:

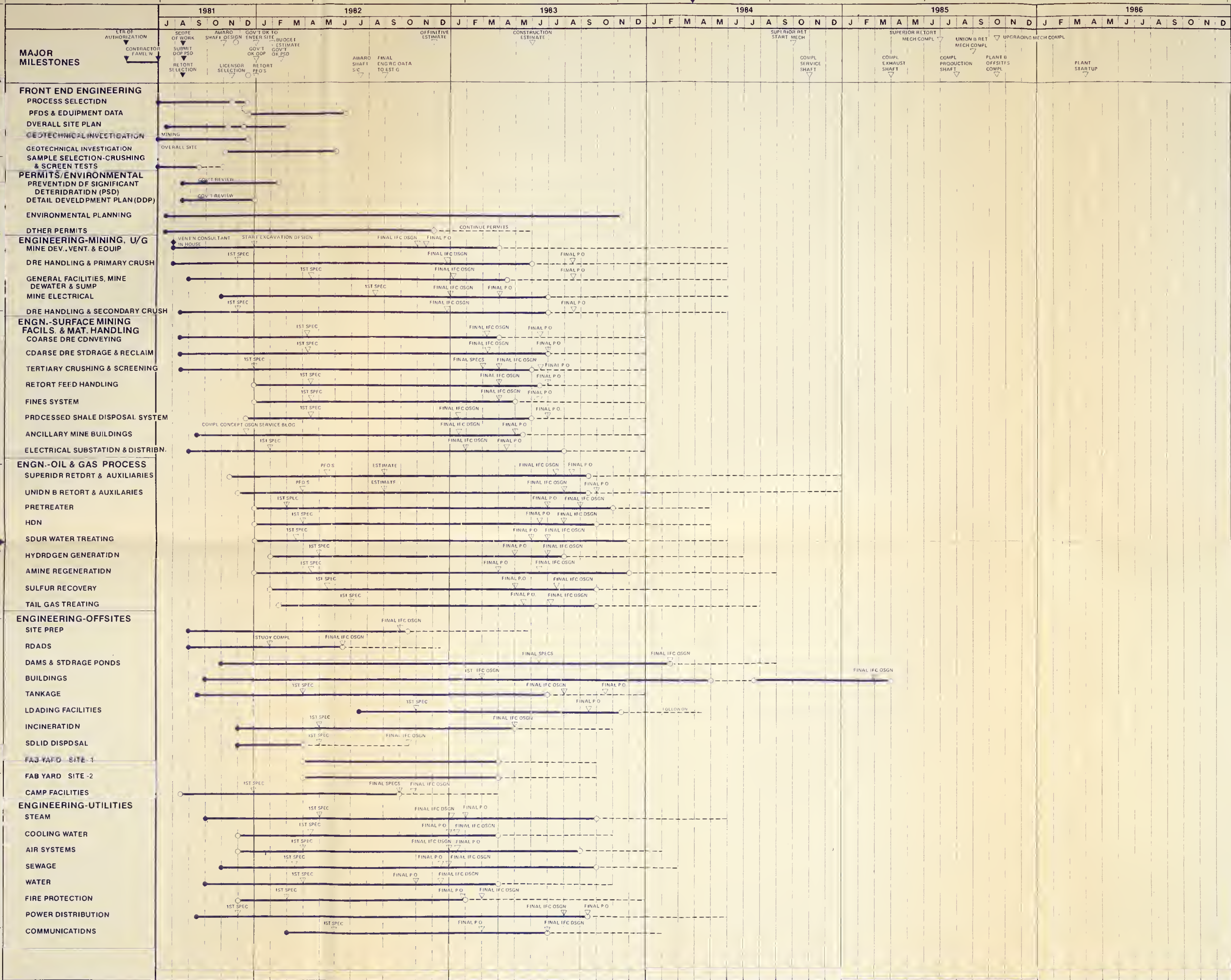
- Preheat System - 45 pounds per hour per train (including 25 pounds per hour condensable hydrocarbons)
- Elutriator - 7 pounds per hour per train
- Moisturizer - 10 pounds per hour per train

The Colony design provides for 40 inches of pressure drop for the lift pipe system scrubber (though it was anticipated that 25 inches would do the job), 40 inches for the elutriator scrubber and 20 inches for the moisturizer scrubber. With one exception, all vendors indicated that the above estimates could be met at the design pressure drops. The single exception is Chemico's quote to Colony for the elutriator scrubber. In general Chemico's quote to Colony showed surprisingly little improvement in increasing scrubber pressure drop from 25 to 40 inches. Though Braun generally agreed with Chemico's projections at that time, Chemico quoted much more optimistic numbers to Rio Blanco and I am reasonably confident that the projections in 1974 were overly pessimistic.

Sincerely yours,

CHARLES S. WAITMAN


TEST & COMMISSIONING
MECH COMP
TEST COMP



NOTES:

GENERAL NOTES

NO 1 THE 1ST SPEC SHOWS WHEN ENGINEERING INPUT IS READY TO DEVELOP REQUESTS TO PROCUREMENT IN ORDER TO OBTAIN PRICING DATA TO SUPPORT THE DEFINITIVE ESTIMATE (± 10%)

NO 2 THE FINAL P.O. INDICATES WHEN A P.O. CAN BE INITIATED IN ORDER TO SUPPORT CONSTRUCTION NEED DATES AS PRESENTLY IDENTIFIED. ACTUAL P.O. RELEASE DATES WILL BE APPROVED BY THE CLIENT

LEGEND:

	SCHEDULED	ACTUAL
MAJOR MILESTONES	▽	▼
START/END ACTIVITIES PROCUREMENT & ENGINEERING	○	●
START/END ACTIVITIES CONSTRUCTION	◇	◆
EQUIP/MATERIAL DELIVERIES	△	▲
SCHEDULE SLIP	·····○	

FOLLOW ON - - - - -

PO - AWARD PURCHASE ORDER
IFC - ISSUED FOR CONSTRUCTION
PFD - PROCESS FLOW DIAGRAM
DDP - DETAILED DEVELOPMENT PLAN
S/C - SUB CONTRACT
VD - VENDOR DATA
B/A - BID ANALYSIS
DBM - DESIGN BASIS MEMORANDUM
RFP - REQUEST FOR PROPOSALS

ENG GF 24 (12 79)

ISSUE FOR INFORMATION

RALPH M. PARSONS COMPANY

WHITE RIVER SHALE PROJECT
TRACTS Ua-Ub

MASTER SCHEDULE
FOR SERVICES

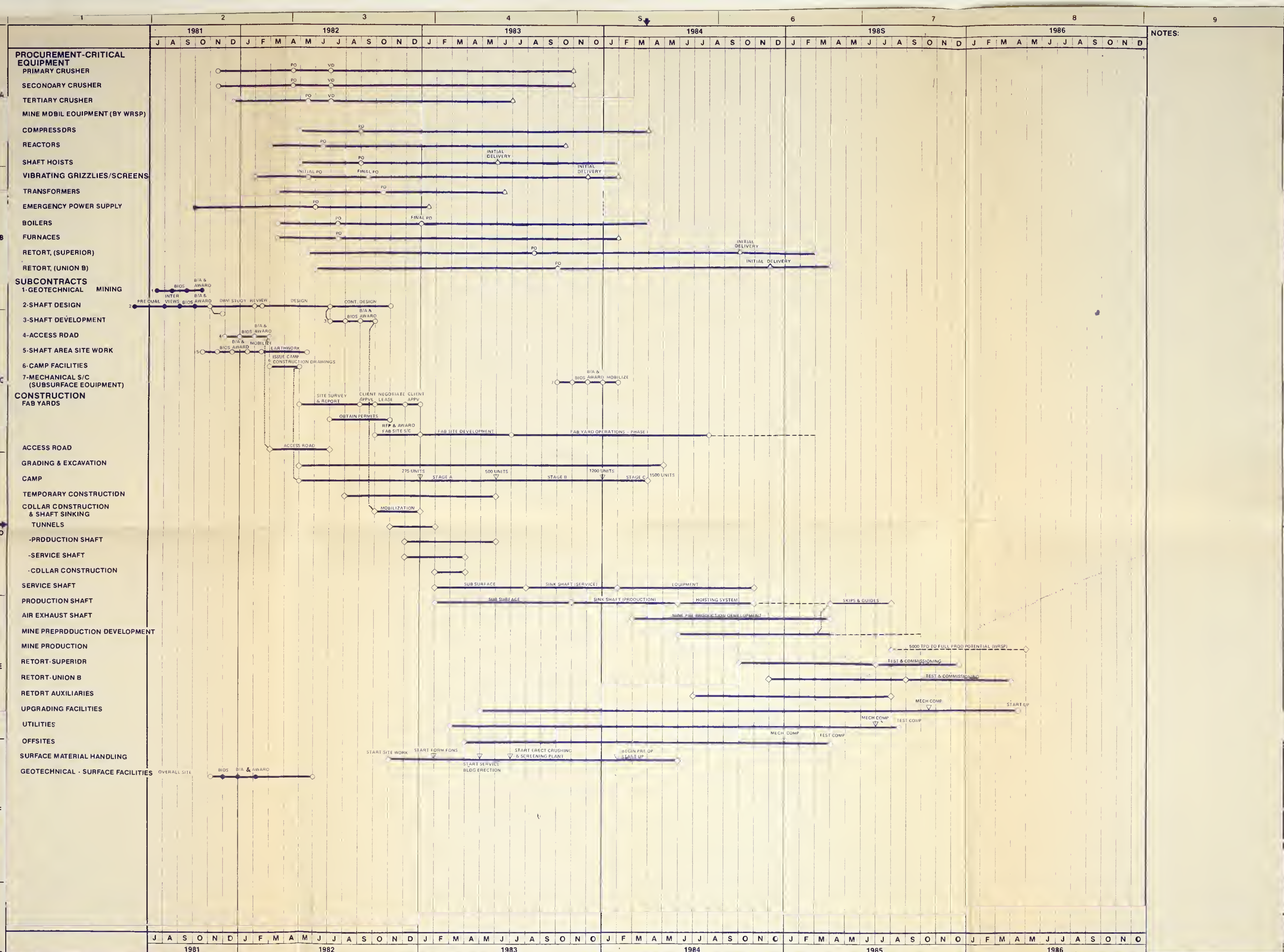
LEVEL 1 SHEET 1 OF 2

6205

SCH-00-PR-1-1

B

DC PE-4 DI 40



LEGEND:

	SCHEDULED	ACTUAL
MAJOR MILESTONES	▽	▼
START/END ACTIVITIES PROCUREMENT & ENGINEERING	○	●
START/END ACTIVITIES CONSTRUCTION	◇	◆
EQUIP./MATERIAL DELIVERIES	△	▲
SCHEDULE SLIP	—○	

FOLLOW ON - - - - -

NO	DATE	BY	CHKD	SEC	PROJ	CLIENT	DESCRIPTION
A	6/26/81						ISSUE FOR INFORMATION
B	12/10/81	JF	CL				

RPP

THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA

WRSP WHITE RIVER SHALE PROJECT
TRACTS Ua-Ub

MASTER SCHEDULE FOR SERVICES
LEVEL 1
SHEET 2 OF 2